Significant Bankruptcy Court Actions

On January 31, 2019, the Bankruptcy Court approved, on an interim basis, certain motions (the "First Day Motions") authorizing, but not directing, PG&E Corporation and the Utility to, among other things, (a) secure $5.5 billion of debtor-in-possession financing; (b) continue to use PG&E Corporation's and the Utility's cash management system; and (c) pay certain pre-petition claims relating to (i) certain safety, reliability, outage, and nuclear facility suppliers; (ii) shippers, warehousemen, and other lien claimants; (iii) taxes; (iv) employee wages, salaries, and other compensation and benefits; and (v) customer programs, including public purpose programs. The First Day Motions were subsequently approved by the Bankruptcy Court on a final basis at hearings on February 27, 2019, March 12, 2019, March 13, 2019, and March 27, 2019.

Debtor-In-Possession Financing

See Note 5 for further discussion of the DIP Facilities, which provide up to $5.5 billion in financing.

Financial Reporting in Reorganization

Effective on the Petition Date, PG&E Corporation and the Utility began to apply accounting standards applicable to reorganizations, which are applicable to companies under Chapter 11 bankruptcy protection. They require the financial statements for periods subsequent to the Petition Date to distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Expenses, realized gains and losses, and provisions for losses that are directly associated with reorganization proceedings must be reported separately as reorganization items, net in the Condensed Consolidated Statements of Income. In addition, the balance sheet must distinguish pre-petition LSTC of PG&E Corporation and the Utility from pre-petition liabilities that are not subject to compromise, post-petition liabilities, and liabilities of the subsidiaries of PG&E Corporation that are not debtors in the Chapter 11 Cases in the Condensed Consolidated Balance Sheets. LSTC are pre-petition obligations that are not fully secured and have at least a possibility of not being repaid at the full claim amount. Where there is uncertainty about whether a secured claim will be paid or impaired pursuant to the Chapter 11 Cases, PG&E Corporation and the Utility have classified the entire amount of the claim as LSTC.

Furthermore, the realization of assets and the satisfaction of liabilities are subject to uncertainty. While operating as debtors-in-possession, certain claims against PG&E Corporation and the Utility in existence before the filing of the petitions for relief under the federal bankruptcy laws are stayed while PG&E Corporation and the Utility continue business operations as debtors in possession. These claims are reflected as LSTC in the Condensed Consolidated Balance Sheets at March 31, 2019. Additional claims (which could be LSTC) may arise after the Petition Date resulting from rejection of executory contracts, including leases, and from the determination by the Bankruptcy Court (or agreement by parties in interest) of allowed claims for contingencies and other disputed amounts.

PG&E Corporation's Condensed Consolidated Financial Statements are presented on a consolidated basis and include the accounts of PG&E Corporation and the Utility and other subsidiaries of PG&E Corporation and the Utility that individually and in aggregate are immaterial. Such other subsidiaries did not file for bankruptcy.

The Utility's Condensed Consolidated Financial Statements are presented on a consolidated basis and include the accounts of the Utility and other subsidiaries of the Utility that individually and in aggregate are immaterial. Such other subsidiaries did not file for bankruptcy.

Liabilities Subject to Compromise

As a result of the commencement of the Chapter 11 Cases, the payment of pre-petition liabilities is generally subject to compromise pursuant to a plan of reorganization. Generally, actions to enforce or otherwise effect payment of pre-petition liabilities are stayed. Although payment of pre-petition claims generally is not permitted, the Bankruptcy Court granted PG&E Corporation and the Utility authority to pay certain pre-petition claims in designated categories and subject to certain terms and conditions. This relief generally was designed to preserve the value of PG&E Corporation's and the Utility's business and assets. Among other things, the Bankruptcy Court authorized, but did not require, PG&E Corporation and the Utility to pay certain pre-petition claims relating to employee wages and benefits, taxes, and certain vendors.

As a result of the Chapter 11 Cases, the payment of pre-petition indebtedness is subject to compromise or other treatment under a plan of reorganization. The determination of how liabilities will ultimately be settled or treated cannot be made until the Bankruptcy Court confirms a Chapter 11 plan of reorganization and such plan becomes effective. Accordingly, the ultimate amount of such liabilities is not determinable at this time. GAAP requires pre-petition liabilities that are subject to compromise to be reported at the amounts expected to be allowed by the Bankruptcy Court, even if they may be settled for different amounts. The amounts currently classified as LSTC are preliminary and may be subject to future adjustments depending on Bankruptcy Court actions, further developments with respect to disputed claims, determinations of the secured status of certain claims, the values of any collateral securing such claims, rejection of executory contracts, continued reconciliation or other events.

The following table presents LSTC as reported in the Condensed Consolidated Balance Sheets at March 31, 2019:

(in millions)	PG&E Corporation [(1)]	Utility	PG&E Corporation Consolidated
Financing debt [(2)]	$ 650	$ 21,811	$ 22,461
Wildfire-related claims [(3)]	—	14,212	14,212
Trade creditors	1	1,850	1,851
Non-qualified benefit plan	122	17	139
2001 bankruptcy disputed claims	—	221	221
Customer deposits & advances	—	272	272
Other	2	164	166
Total Liabilities Subject to Compromise	**$ 775**	**$ 38,547**	**$ 39,322**

(1) PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.
(2) At March 31, 2019, PG&E Corporation and the Utility had $650 million and $21,526 million in aggregate principal amount of indebtedness, respectively. Utility financing debt also includes $285 million of accrued contractual interest to the Petition Date. See Note 5 for details of pre-petition debt reported as LSTC.
(3) See Note 10 for details of pre-petition wildfire-related claims reported as LSTC.

Reorganization Items, Net

Reorganization items, net represent amounts incurred after the Petition Date as a direct result of the Chapter 11 Cases and are comprised of professional fees and financing costs, net of interest income. Reorganization items also include adjustments to reflect the carrying value of LSTC at their estimated allowed claim amounts, as such adjustments are determined. Cash paid for reorganization items, net was $17 million and $91 million for PG&E Corporation and the Utility, respectively, during the three months ended March 31, 2019. Reorganization items, net as of March 31, 2019 include the following:

	Post-Petition Period Through March 31, 2019		
(in millions)	PG&E Corporation [(1)]	Utility	PG&E Corporation Consolidated
Debtor-in-possession financing costs	17	97	114
Legal and other	$ 1	$ 23	$ 24
Interest income	(2)	(9)	(11)
Total reorganization items, net	**$ 16**	**$ 111**	**$ 127**

(1) PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.

Contractual Interest on Debt Subject to Compromise

Effective as of the Petition Date, PG&E Corporation and the Utility ceased recording interest expense on outstanding pre-petition debt. Contractual interest expense represents amounts due under the contractual terms of outstanding pre-petition debt. From the Petition Date through March 31, 2019, contractual interest expense of $166 million related to LSTC has not been recorded in the financial statements. Additionally, the portion of authorized revenues from the Petition Date through March 31, 2019 related to interest expense on pre-petition debt has been deferred as a non-current regulatory liability.

Resolution of Remaining 2001 Chapter 11 Disputed Claims

Various electricity suppliers filed claims in the Utility's 2001 prior proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. While the FERC and judicial proceedings are pending, the Utility pursued settlements with electricity suppliers and entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Under these settlement agreements, amounts payable by the parties, in some instances, would be subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

The Utility's obligations with respect to such claims (all of which arose prior to the initiation of the Utility's pending Chapter 11 Case on January 29, 2019), including pursuant to any prior settlements relating thereto, are expected to be determined through the proceedings of the Chapter 11 Cases.

NOTE 3: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

For a summary of the significant accounting policies used by PG&E Corporation and the Utility, see Note 2 of the Condensed Consolidated Financial Statements above and Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.

Variable Interest Entities

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility has a controlling interest or was the primary beneficiary of any of these VIEs at March 31, 2019, the Utility assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at March 31, 2019, it did not consolidate any of them.

Pension and Other Post-Retirement Benefits

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan and cash balance plan. Both plans are included in "Pension Benefits" below. Post-retirement medical and life insurance plans are included in "Other Benefits" below.

The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Financial Statements for the three months ended March 31, 2019 and 2018 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended March 31,			
(in millions)	**2019**	**2018**	**2019**	**2018**
Service cost for benefits earned [1]	$ 111	$ 128	$ 14	$ 16
Interest cost	189	172	19	17
Expected return on plan assets	(227)	(255)	(31)	(33)
Amortization of prior service cost	(1)	(1)	4	4
Amortization of net actuarial loss	1	1	(1)	(1)
Net periodic benefit cost	**73**	**45**	**5**	**3**
Regulatory account transfer [2]	10	39	—	—
Total	**$ 83**	**$ 84**	**$ 5**	**$ 3**

[1] A portion of service costs are capitalized pursuant to ASU 2017-07.
[2] The Utility recorded these amounts to a regulatory account since they are probable of recovery from, or refund to, customers in future rates

Non-service costs are reflected in Other income, net on the Condensed Consolidated Statements of Income. Service costs are reflected in Operating and maintenance on the Condensed Consolidated Statements of Income.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

On February 27, 2019, PG&E Corporation and the Utility received final approval from the Bankruptcy Court to maintain existing pension and other benefit plans during the pendency of the Chapter 11 Cases.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (Loss)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) are summarized below:

	Pension Benefits	Other Benefits	Total
(in millions, net of income tax)	Three Months Ended March 31, 2019		
Beginning balance	$ (21)	$ 17	$ (4)
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of $0 and $1, respectively) [1]	(1)	3	2
Amortization of net actuarial loss (net of taxes of $0 and $0, respectively) [1]	1	(1)	—
Regulatory account transfer (net of taxes of $0 and $1, respectively) [1]	—	(2)	(2)
Net current period other comprehensive gain (loss)	**—**	**—**	**—**
Ending balance	**$ (21)**	**$ 17**	**$ (4)**

[1] These components are included in the computation of net periodic pension and other post-retirement benefit costs. (See the "Pension and Other Post-Retirement Benefits" table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Three Months Ended March 31, 2018		
Beginning balance	$ (25)	$ 17	$ (8)
Amounts reclassified from other comprehensive income: [(1)]			
Amortization of prior service cost (net of taxes of $0 and $1, respectively)	(1)	3	2
Amortization of net actuarial loss (net of taxes of $0 and $0, respectively)	1	(1)	—
Regulatory account transfer (net of taxes of $0 and $1, respectively)	—	(2)	(2)
Reclassification of stranded income tax to retained earnings (net of taxes of $0 and $0, respectively)	**(5)**	**—**	**(5)**
Net current period other comprehensive gain (loss)	**(5)**	**—**	**(5)**
Ending balance	**$ (30)**	**$ 17**	**$ (13)**

[(1)] These components are included in the computation of net periodic pension and other post-retirement benefit costs. (See the "Pension and Other Post-Retirement Benefits" table above for additional details.)

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Revenue Recognition

Revenue from Contracts with Customers

The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Condensed Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements. Revenues can vary significantly from period to period because of seasonality, weather, and customer usage patterns.

Regulatory Balancing Account Revenue

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and its GT&S rate cases, which generally occur every three or four years. The Utility's ability to recover revenue requirements authorized by the CPUC in these rate cases is independent, or "decoupled," from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, electric and natural gas operating revenue is recognized ratably over the year. The Utility records a balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas, and to fund public purpose, demand response, and customer energy efficiency programs. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred. The Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. As a result, these differences have no impact on net income.

The following table presents the Utility's revenues disaggregated by type of customer:

	Three Months Ended March 31,	
(in millions)	2019	2018
Electric		
Revenue from contracts with customers		
Residential	$ 1,288	$ 1,336
Commercial	953	1,073
Industrial	293	324
Agricultural	86	125
Public street and highway lighting	17	20
Other [1]	(309)	(201)
Total revenue from contracts with customers - electric	2,328	2,677
Regulatory balancing accounts [2]	464	274
Total electric operating revenue	**$ 2,792**	**$ 2,951**
Natural gas		
Revenue from contracts with customers		
Residential	$ 1,171	$ 958
Commercial	240	196
Transportation service only	382	297
Other [1]	(75)	(52)
Total revenue from contracts with customers - gas	1,718	1,399
Regulatory balancing accounts [2]	(499)	(294)
Total natural gas operating revenue	**1,219**	**1,105**
Total operating revenues	**$ 4,011**	**$ 4,056**

[1] This activity is primarily related to the change in unbilled revenue, partially offset by other miscellaneous revenue items.
[2] These amounts represent revenues authorized to be billed or refunded to customers.

Recently Adopted Accounting Standards

Recognition of Lease Assets and Liabilities

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, which amends the guidance relating to the definition of a lease, the recognition of lease assets and lease liabilities on the balance sheet, and the disclosure of key information about leasing arrangements. Under the new standard, all lessees must recognize a ROU asset, reflecting the right to use the underlying asset for the lease term, and a lease liability, reflecting the obligation to make lease payments, on the balance sheet. Operating leases were previously not recognized on the balance sheet. PG&E Corporation and the Utility adopted the ASU on January 1, 2019.

PG&E Corporation and the Utility elected certain practical expedients and will carry forward historical conclusions related to (1) contracts that contain leases, (2) existing lease and easement classification, and (3) initial direct costs. After adoption of the new standard, the Corporation and Utility elected to not separate lease and non-lease components. Additionally, PG&E Corporation and the Utility have elected not to restate comparative periods upon adoption.

PG&E Corporation and the Utility determine if an arrangement is a lease at inception. As most of the leases do not provide implicit discount rates, the Utility uses an estimate of its incremental secured borrowing rates based on observed market data and other information available at the lease commencement date. The ROU assets and lease liabilities include only fixed lease payments, and leases with an initial term of 12 months or less are not recorded on the balance sheet. Lease terms will only include options to extend or terminate the lease when it is reasonably certain that the Utility will exercise such options. The Utility recognizes lease expense in conformity with ratemaking.

Operating leases are included in operating lease ROU assets and current and noncurrent operating lease liabilities on the Condensed Consolidated Balance Sheets. Finance leases are included in property, plant, and equipment, other current liabilities, and other noncurrent liabilities on the Condensed Consolidated Balance Sheets. Financing leases were immaterial for the three months ended March 31, 2019.

Cash payments arising from operating leases were $335 million for the three months ended March 31, 2019 and are presented within operating activities on the Condensed Consolidated Statement of Cash Flows. Cash payments for the principal portion of the financing lease liability will continue to be presented within financing activities. Variable lease payments, if any, not included in the financing lease liability, if any, are presented within operating activities. On January 1, 2019, PG&E Corporation and the Utility recorded ROU assets and lease liabilities of $2.8 billion, representing the net present value of fixed lease payments and excluding any variable lease payments. This amount is presented within the supplemental disclosures of noncash activities for the three months ended, March 31, 2019.

The majority of the Utility's ROU assets and lease liabilities relate to various power purchase agreements. These power purchase agreements primarily consist of generation plants leased to meet customer demand plus applicable reserve margins, for terms between 5 years and 20 years. PG&E Corporation and the Utility have also recorded ROU assets and lease liabilities related to property and land leases.

At March 31, 2019, the Utility's operating leases had a weighted average remaining lease term of 6.3 years and a weighted average discount rate of 6.11%.

The following table shows the lease expense recognized for the fixed and variable component of the Utility's lease obligations:

(in millions)		**Three Months Ended March 31, 2019**
Operating lease fixed cost	$	122
Operating lease variable cost		309
Total operating lease costs	**$**	**431**

The following table shows the Utility's future expected operating lease payments:

(in millions)		**March 31, 2019**
2019	$	686
2020		669
2021		616
2022		523
2023		195
Thereafter		672
Total lease payments		**3,361**
Less imputed interest		(633)
Total	**$**	**2,728**

The following table shows the Utility's future expected obligations for power purchase and other lease commitments:

(in millions)		**December 31, 2018**
2019	$	684
2020		677
2021		621
2022		546
2023		252
Thereafter		581
Total lease commitments	**$**	**3,361**

Accounting Standards Issued But Not Yet Adopted

Fair Value Measurement

In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurement (Topic 820): Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurements*, which amends the existing guidance relating to the disclosure requirements for fair value measurements. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2020 with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Condensed Consolidated Financial Statements and related disclosures.

Intangibles-Goodwill and Other

In August 2018, the FASB issued ASU No. 2018-15, *Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract.* This ASU will be effective for PG&E Corporation and the Utility on January 1, 2020 with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Condensed Consolidated Financial Statements and related disclosures.

NOTE 4: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets and Liabilities

Long-Term Regulatory Assets

Long-term regulatory assets are comprised of the following:

(in millions)	Asset Balance at March 31, 2019	Asset Balance at December 31, 2018
Pension benefits [1]	$ 1,938	$ 1,947
Environmental compliance costs	932	1,013
Utility retained generation [2]	262	274
Price risk management	65	90
Unamortized loss, net of gain, on reacquired debt [3]	237	76
Catastrophic event memorandum account [4]	865	790
Wildfire expense memorandum account [5]	111	94
Fire hazard prevention memorandum account [6]	329	263
Other	412	417
Total long-term regulatory assets	**$ 5,151**	**$ 4,964**

(1) Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the Utility expects to continuously recover pension benefits.
(2) In connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's 2001 proceeding under Chapter 11, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.
(3) Includes the accelerated amortization of premiums and debt issuance costs on pre-petition debt.
(4) Includes costs of responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities. Recovery of CEMA costs are subject to CPUC review and approval.
(5) Includes specific incremental wildfire liability costs the CPUC approved for tracking in June 2018. Recovery of WEMA costs are subject to CPUC review and approval.
(6) Includes costs associated with the implementation of regulations and requirements adopted to protect the public from potential fire hazards associated with overhead power line facilities and nearby aerial communication facilities that have not been previously authorized in another proceeding. Recovery of FHPMA costs are subject to CPUC review and approval.

Current Regulatory Liabilities

Current regulatory liabilities are primarily comprised of the current portion of the tax reform adjustment recorded as a result of the Tax Act.

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

(in millions)	Liability Balance at March 31, 2019	Liability Balance at December 31, 2018
Cost of removal obligations [1]	$ 6,134	$ 5,981
Deferred income taxes [2]	142	283
Recoveries in excess of AROs [3]	471	356
Public purpose programs [4]	758	674
Retirement Plan [5]	422	421
Other	945	824
Total long-term regulatory liabilities	**$ 8,872**	**$ 8,539**

(1) Represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.
(2) Represents the net of amounts owed to customers for deferred taxes collected at higher rates before the Tax Act and amounts owed to the Utility for reversal of deferred taxes subject to flow-through treatment.
(3) Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on these nuclear decommissioning trust investments. (See Note 9 below.)
(4) Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.
(5) Represents cumulative differences between incurred costs and amounts collected in rates for Post-Retirement Medical, Post-Retirement Life and Long Term Disability Plans.

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.

Regulatory Balancing Accounts

Current regulatory balancing accounts receivable and payable are comprised of the following:

	Receivable Balance at	
(in millions)	**March 31, 2019**	**December 31, 2018**
Electric distribution	$ 449	$ 160
Electric transmission	128	128
Utility generation	357	79
Gas distribution and transmission	70	462
Energy procurement	137	168
Public purpose programs	76	111
Other	280	327
Total regulatory balancing accounts receivable	**$ 1,497**	**$ 1,435**

	Payable Balance at	
(in millions)	**March 31, 2019**	**December 31, 2018**
Electric transmission	146	134
Gas distribution and transmission	51	9
Energy procurement	223	59
Public purpose programs	600	587
Other	325	287
Total regulatory balancing accounts payable	**$ 1,345**	**$ 1,076**

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.

NOTE 5: DEBT

Debtor-In-Possession Facilities

In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement, among the Utility, as borrower, PG&E Corporation, as guarantor, JPMorgan Chase Bank, N.A., as administrative agent, Citibank, N.A., as collateral agent, and the lenders and issuing banks party thereto (together with such other financial institutions from time to time party thereto, the "DIP Lenders"). The DIP Credit Agreement provides for $5.5 billion in senior secured superpriority debtor in possession credit facilities in the form of (i) a revolving credit facility in an aggregate amount of $3.5 billion (the "DIP Revolving Facility"), including a $1.5 billion letter of credit subfacility, (ii) a term loan facility in an aggregate principal amount of $1.5 billion (the "DIP Initial Term Loan Facility") and (iii) a delayed draw term loan facility in an aggregate principal amount of $500 million (the "DIP Delayed Draw Term Loan Facility", together with the DIP Revolving Facility and the DIP Initial Term Loan Facility, the "DIP Facilities"), subject to the terms and conditions set forth therein.

On the Petition Date, PG&E Corporation and the Utility filed a motion seeking, among other things, interim and final approval of the DIP Facilities, which motion was granted on an interim basis by the Bankruptcy Court following a hearing on January 31, 2019. As a result of the Bankruptcy Court's interim approval of the DIP Facilities and the satisfaction of the other conditions thereof, the DIP Credit Agreement became effective on February 1, 2019 and a portion of the DIP Revolving Facility in the amount of $1.5 billion (including $750 million of the letter of credit subfacility) was made available to the Utility. On March 27, 2019, the Bankruptcy Court approved the DIP Facilities on a final basis, authorizing the Utility to borrow up to the remainder of the DIP Revolving Facility (including the remainder of the $1.5 billion letter of credit subfacility), the DIP Initial Term Loan Facility and the DIP Delayed Draw Term Loan Facility, in each case subject to the terms and conditions of the DIP Credit Agreement.

Borrowings under the DIP Facilities are senior secured obligations of the Utility, secured by substantially all of the Utility's assets and entitled to superpriority administrative expense claim status in the Utility's Chapter 11 Case. The Utility's obligations under the DIP Facilities are guaranteed by PG&E Corporation, and such guarantee is a senior secured obligation of PG&E Corporation, secured by substantially all of PG&E Corporation's assets and entitled to superpriority administrative expense claim status in PG&E Corporation's Chapter 11 Case.

On February 1, 2019, the Utility borrowed $350 million under the DIP Revolving Facility. On April 3, 2019, following the Bankruptcy Court's final approval of the DIP Facilities, the Utility borrowed $1.5 billion under the DIP Initial Term Loan Facility and repaid the $350 million outstanding under the DIP Revolving Facility.

The commencement of the Chapter 11 Cases constituted an event of default or termination event with respect to, and caused an automatic and immediate acceleration of the debt outstanding under or in respect of, certain instruments and agreements relating to direct financial obligations of PG&E Corporation and the Utility (the "Accelerated Direct Financial Obligations"). However, any efforts to enforce such payment obligations are automatically stayed as of the Petition Date, and are subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The material Accelerated Direct Financial Obligations include the Utility's outstanding senior notes, agreements in respect of certain series of pollution control bonds, and PG&E Corporation's term loan facility, as well as short-term borrowings under PG&E Corporation's and the Utility's revolving credit facilities and the Utility's term loan facility. For more information, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.

Debtor-in-Possession Financing

The following table summarizes the Utility's outstanding borrowings and availability under the DIP Facilities at March 31, 2019:

(in millions)	Termination Date	Limit	Letters of Credit Outstanding	Borrowings Against DIP Revolving Facility	Availability
DIP Facilities	**December 2020** (1)	**$ 1,500** (2)	**$ 131**	**$ 350**	**$ 1,019**

(1) May be extended to December 2021, subject to satisfaction of certain terms and conditions, including payment of a 25 basis point extension fee.
(2) On March 27, 2019, the Bankruptcy Court approved the DIP Facilities in full, but the conditions precedent to the full availability of the DIP Facilities were not satisfied until April 3, 2019. Accordingly, the amounts set forth in this table are based on the interim availability under the DIP Revolving Facility of $1.5 billion.

As of March 31, 2019, PG&E Corporation and the Utility each had no commercial paper borrowings outstanding. PG&E Corporation and the Utility do not expect to be able to access the commercial paper market for the duration of the Chapter 11 Cases.

Debt

The following table summarizes PG&E Corporation's and the Utility's outstanding debt subject to compromise:

(in millions)	Contractual Interest Rates	Balance at, March 31, 2019	Balance at, December 31, 2018
Debt Subject to Compromise [(1)]			
PG&E Corporation			
Borrowings under Pre-Petition Credit Facilities			
PG&E Corporation Revolving Credit Facilities - Stated Maturity: 2022	variable rate[(2)]	$ 300	$ 300
Other borrowings:			
Term Loan - Stated Maturity: 2020	variable rate[(3)]	350	350
Total PG&E Corporation Debt Subject to Compromise		**650**	**650**
Utility			
Senior Notes - Stated Maturity:			
2020	3.50%	800	800
2021	3.25% to 4.25%	550	550
2022	2.45%	400	400
2023	3.25% to 4.25%	1,175	1,175
2024 through 2046	2.95% to 6.35%	14,600	14,600
Unamortized discount, net or premium and debt issuance costs		—	(178)
Total Senior notes, net of premium and debt issuance costs		**17,525**	**17,347**
Pollution Control Bonds - Stated Maturity:			
Series 2008 F and 2010 E, due 2026 [(4)]	1.75%	100	100
Series 2009 A-B, due 2026 [(5)]	variable rate [(6)]	149	149
Series 1996 C, E, F, 1997 B due 2026 [(5)]	variable rate [(7)]	614	614
Total pollution control bonds		**863**	**863**
Borrowings under Pre-Petition Credit Facilities			
Utility Revolving Credit Facilities - Stated Maturity: 2022 [(8)]	variable rate[(9)]	2,965	2,965
Other borrowings:			
Term Loan - Stated Maturity: 2019	variable rate[(10)]	250	250
Total Borrowings under Pre-Petition Credit Facility Subject to Compromise		**3,215**	**3,215**
Total Utility Debt Subject to Compromise		**21,603**	**21,425**
Total PG&E Corporation Consolidated Debt Subject to Compromise		**$ 22,253**	**$ 22,075**

(1) LSTC must be reported at the amounts expected to be allowed by the Bankruptcy Court. The carrying value of the debt subject to compromise will be adjusted as claims are approved. As of March 31, 2019, PG&E Corporation and the Utility wrote off $178 million of unamortized debt issuance costs and debt discount to present the debt subject to compromise at the outstanding face value. The write-offs are included within long-term regulatory assets in the Condensed Consolidated Statements of Income. See Notes 2 and 4 for further details.

(2) At March 31, 2019, the contractual LIBOR-based interest rate on loans were 3.97%.

(3) At March 31, 2019, the contractual LIBOR-based interest rate on the term loan was 3.71%.

(4) Pollution Control Bonds series 2008F and 2010E were reissued in June 2017. Although the stated maturity date for both series is 2026, these bonds have a mandatory redemption date of May 31, 2022.

(5) Each series of these bonds is supported by a separate direct-pay letter of credit. Following the Utility's Chapter 11 filing, investors in these bonds drew on the letter of credit facilities. The letter of credit facility supporting the Series 2009 A-B bonds has a maturity date of June 5, 2019. In December 2015, the maturity dates of the letter of credit facilities supporting the Series 1996 C, E, F, 1997 B bonds were extended to December 1, 2020. Although the stated maturity date of these bonds is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.
(6) At March 31, 2019, the contractual interest rate on the letter of credit facility supporting these bonds was 4.13%.
(7) At March 31, 2019, the contractual interest rate on the letter of credit facility supporting these bonds ranged from 4.13% to 4.47%.
(8) Also includes $80 million in letters of credit.
(9) At March 31, 2019, the contractual LIBOR-based interest rate was 3.67%.
(10) At March 31, 2019, the contractual LIBOR-based interest rate was 3.09%.

NOTE 6: EQUITY

PG&E Corporation's changes in equity for the three months ended March 31, 2019 and 2018 were as follows:

(in millions, except share amounts)	Common Stock Shares	Common Stock Amount	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Non controlling Interest - Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2018	**520,338,710**	**$ 12,910**	**$ (250)**	**$ (9)**	**$ 12,651**	**$ 252**	**$ 12,903**
Net income (loss)	—	—	136	—	136	—	136
Other comprehensive loss	—	—	—	—	—	—	—
Common stock issued, net	8,871,568	85	—	—	85	—	85
Stock-based compensation amortization	—	5	—	—	5	—	5
Balance at March 31, 2019	**529,210,278**	**$ 13,000**	**$ (114)**	**$ (9)**	**$ 12,877**	**$ 252**	**$ 13,129**

(in millions, except share amounts)	Common Stock Shares	Common Stock Amount	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Non controlling Interest - Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2017	**514,775,845**	**$ 12,632**	**$ 6,596**	**$ (8)**	**$ 19,220**	**$ 252**	**$ 19,472**
Net income	—	—	445	—	445	—	445
Other comprehensive income	—	—	—	—	—	—	—
Common stock issued, net	1,248,112	35	—	—	35	—	35
Stock-based compensation amortization	—	34	—	—	34	—	34
Preferred stock dividend requirement of subsidiary	—	—	(3)	—	(3)	—	(3)
Balance at March 31, 2018	**516,023,957**	**$ 12,701**	**$ 7,038**	**$ (8)**	**$ 19,731**	**$ 252**	**$ 19,983**

The Utility's changes in equity for the three months ended March 31, 2019 and 2018 were as follows:

(in millions)	Preferred Stock	Common Stock Amount	Additional Paid-in Capital	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2018	**$ 258**	**$ 1,322**	**$ 8,550**	**$ 2,826**	**$ (1)**	**$ 12,955**
Net income (loss)	—	—	—	133	—	133
Other comprehensive loss	—	—	—	—	—	—
Equity contribution	—	—	—	—	—	—
Preferred stock dividend	—	—	—	—	—	—
Balance at March 31, 2019	**$ 258**	**$ 1,322**	**$ 8,550**	**$ 2,959**	**$ (1)**	**$ 13,088**

(in millions)	Preferred Stock	Common Stock Amount	Additional Paid-in Capital	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2017	**258**	**1,322**	**8,505**	**9,656**	**6**	**$ 19,747**
Net income	—	—	—	452	—	452
Other comprehensive income	—	—	—	2	(2)	—
Equity contribution	—	—	—	—	—	—
Common stock dividend	—	—	—	—	—	—
Preferred stock dividend	—	—	—	(3)	—	(3)
Balance at March 31, 2018	**$ 258**	**$ 1,322**	**$ 8,505**	**$ 10,107**	**$ 4**	**$ 20,196**

There were no issuances under the PG&E Corporation February 2017 equity distribution agreement for the three months ended March 31, 2019.

PG&E Corporation issued common stock under the PG&E Corporation 401(k) plan and share-based compensation plans. During the three months ended March 31, 2019, 8.9 million shares were issued for cash proceeds of $85 million under these plans. Beginning January 1, 2019 PG&E Corporation changed its default matching contributions under its 401(k) plan from PG&E Corporation common stock to cash. Beginning in March 2019, at PG&E Corporation's directive, the 401(k) plan trustee began purchasing new shares in the PG&E Corporation common stock fund on the open market rather than directly from PG&E Corporation.

Dividends

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility suspended quarterly cash dividends on both PG&E Corporation's and the Utility's common stock, beginning the fourth quarter of 2017, as well as the Utility's preferred stock, beginning the three-month period ending January 31, 2018, due to the uncertainty related to the causes of and potential liabilities associated with the Northern California wildfires. See Wildfire-related contingencies in Note 10 below.

The DIP Credit Agreement includes usual and customary covenants for debtor-in-possession loan agreements of this type, including covenants limiting PG&E Corporation's and the Utility's ability to, among other things, declare and pay any dividend or make any other distributions with respect to any of their capital stock. Also, on April 3, 2019, the court overseeing the Utility's probation issued an order imposing new conditions of probation, including foregoing issuing "any dividends until [the Utility] is in compliance with all applicable vegetation management requirements under applicable law and the Utility's wildfire mitigation plan." PG&E Corporation does not expect to pay any cash dividends during the Chapter 11 Cases.

NOTE 7: EARNINGS PER SHARE

PG&E Corporation's basic EPS are calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS:

	Three Months Ended March 31,	
(in millions, except per share amounts)	**2019**	**2018**
Income available for common shareholders	**$ 136**	**$ 445**
Preferred stock dividend requirement of subsidiary	3	3
Adjusted income available for common shareholders	**133**	**442**
Weighted average common shares outstanding, basic	526	515
Add incremental shares from assumed conversions:		
Employee share-based compensation	1	1
Weighted average common shares outstanding, diluted	**527**	**516**
Total earnings per common share, diluted	**$ 0.25**	**$ 0.86**

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

NOTE 8: DERIVATIVES

Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Derivatives are presented in the Utility's Condensed Consolidated Balance Sheets recorded at fair value and on a net basis in accordance with master netting arrangements for each counter-party. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Condensed Consolidated Balance Sheets. These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives under the applicable ratemaking mechanism in place as long as the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Condensed Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. These items are not reflected in the Condensed Consolidated Balance Sheets.

Volume of Derivative Activity

The volumes of the Utility's outstanding derivatives were as follows:

		Contract Volume at	
Underlying Product	**Instruments**	**March 31, 2019**	**December 31, 2018**
Natural Gas [1] (MMBtus [2])	Forwards, Futures and Swaps	138,016,980	177,750,349
	Options	4,115,000	13,735,405
Electricity (Megawatt-hours)	Forwards, Futures and Swaps	3,011,826	3,833,490
	Congestion Revenue Rights [3]	335,556,726	340,783,089

[1] Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.
[2] Million British Thermal Units.
[3] CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

Presentation of Derivative Instruments in the Financial Statements

At March 31, 2019, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 45	$ (2)	$ 38	$ 81
Other noncurrent assets – other	165	1	—	166
Current liabilities – other	(37)	17	3	(17)
Noncurrent liabilities – other	(49)	(16)	—	(65)
Total commodity risk	**$ 124**	**$ —**	**$ 41**	**$ 165**

At December 31, 2018, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 44	$ (1)	$ 89	$ 132
Other noncurrent assets – other	165	—	—	165
Current liabilities – other	(29)	1	7	(21)
Noncurrent liabilities – other	(90)	—	2	(88)
Total commodity risk	**$ 90**	**$ —**	**$ 98**	**$ 188**

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Condensed Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives instruments, including power purchase agreements, contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies, also known as a credit-risk-related contingent feature. During the first quarter, multiple credit rating agencies downgraded the Utility's credit rating below investment grade, which resulted in the Utility posting approximately $7 million in collateral. At March 31, 2019, the Utility fully satisfied its obligations related to the credit-risk related contingency feature.

NOTE 9: FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility measure their cash equivalents, trust assets, and price risk management instruments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 –** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 –** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 –** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below. Assets held in rabbi trusts are held by PG&E Corporation and not the Utility.

	Fair Value Measurements				
	March 31, 2019				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting** (1)	**Total**
Assets:					
Short-term investments	**$ 2,898**	**$ —**	**$ —**	**$ —**	**$ 2,898**
Nuclear decommissioning trusts					
Short-term investments	18	—	—	—	**18**
Global equity securities	1,882	—	—	—	**1,882**
Fixed-income securities	790	692	—	—	**1,482**
Assets measured at NAV	—	—	—	—	**18**
Total nuclear decommissioning trusts (2)	**2,690**	**692**	**—**	**—**	**3,400**
Price risk management instruments (Note 8)					
Electricity	—	1	209	15	**225**
Gas	—	—	—	22	**22**
Total price risk management instruments	**—**	**1**	**209**	**37**	**247**
Rabbi trusts					
Fixed-income securities	—	96	—	—	**96**
Life insurance contracts	—	69	—	—	**69**
Total rabbi trusts	**—**	**165**	**—**	**—**	**165**
Long-term disability trust					
Short-term investments	8	—	—	—	**8**
Assets measured at NAV	—	—	—	—	**146**
Total long-term disability trust	**8**	**—**	**—**	**—**	**154**
TOTAL ASSETS	**$ 5,596**	**$ 858**	**$ 209**	**$ 37**	**$ 6,864**
Liabilities:					
Price risk management instruments (Note 8)					
Electricity	$ 1	$ 3	$ 80	$ (4)	**$ 80**
Gas	—	2	—	—	**2**
TOTAL LIABILITIES	**$ 1**	**$ 5**	**$ 80**	**$ (4)**	**$ 82**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $468 million, primarily related to deferred taxes on appreciation of investment value.

	Fair Value Measurements				
	December 31, 2018				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Short-term investments	**$ 1,593**	**$ —**	**$ —**	**$ —**	**$ 1,593**
Nuclear decommissioning trusts					
Short-term investments	29	—	—	—	**29**
Global equity securities	1,793	—	—	—	**1,793**
Fixed-income securities	661	639	—	—	**1,300**
Assets measured at NAV	—	—	—	—	**16**
Total nuclear decommissioning trusts (2)	**2,483**	**639**	**—**	**—**	**3,138**
Price risk management instruments (Note 8)					
Electricity	—	5	203	51	**259**
Gas	—	1	—	37	**38**
Total price risk management instruments	**—**	**6**	**203**	**88**	**297**
Rabbi trusts					
Fixed-income securities	—	93	—	—	**93**
Life insurance contracts	—	67	—	—	**67**
Total rabbi trusts	**—**	**160**	**—**	**—**	**160**
Long-term disability trust					
Short-term investments	7	—	—	—	**7**
Assets measured at NAV	—	—	—	—	**155**
Total long-term disability trust	**7**	**—**	**—**	**—**	**162**
TOTAL ASSETS	**$ 4,083**	**$ 805**	**$ 203**	**$ 88**	**$ 5,350**
Liabilities:					
Price risk management instruments (Note 8)					
Electricity	$ 4	$ 5	$ 108	$ (10)	**$ 107**
Gas	—	2	—	—	**2**
TOTAL LIABILITIES	**$ 4**	**$ 7**	**$ 108**	**$ (10)**	**$ 109**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $408 million, primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the three months ended March 31, 2019 and 2018.

Trust Assets

Assets Measured at Fair Value

In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks. Nuclear decommissioning trust assets and other trust assets are composed primarily of equity and fixed-income securities and also include short-term investments that are money market funds valued at Level 1.

Global equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1.

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of fixed-income securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

Assets Measured at NAV Using Practical Expedient

Investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Condensed Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

Price Risk Management Instruments

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded futures that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded futures, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility utilizes historical prices to forecast forward prices. CRRs are classified as Level 3.

Level 3 Measurements and Sensitivity Analysis

The Utility's market and credit risk management function, which reports to PG&E Corporation's Chief Financial Officer, is responsible for determining the fair value of the Utility's price risk management derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 8 above.)

(in millions)	Fair Value at March 31, 2019				
Fair Value Measurement	**Assets**	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Range [(1)]**
Congestion revenue rights	$ 203	$ 60	Market approach	CRR auction prices	$(36.87) - 23.04
Power purchase agreements	$ 6	$ 20	Discounted cash flow	Forward prices	$ 19.81 - 38.80

(1) Represents price per megawatt-hour.

(in millions)	Fair Value at December 31, 2018				
Fair Value Measurement	**Assets**	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Range [(1)]**
Congestion revenue rights	$ 203	$ 75	Market approach	CRR auction prices	$ (18.61) - 32.26
Power purchase agreements	$ —	$ 33	Discounted cash flow	Forward prices	$ 19.81 - 38.80

(1) Represents price per megawatt-hour.

Level 3 Reconciliation

The following tables present the reconciliation for Level 3 price risk management instruments for the three months ended March 31, 2019 and 2018:

	Price Risk Management Instruments	
(in millions)	**2019**	**2018**
Asset (liability) balance as of January 1	**$ 95**	**$ 42**
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts [(1)]	34	(2)
Asset (liability) balance as of March 31	**$ 129**	**$ 40**

(1) The costs related to price risk management activities are fully passed through to customers in rates. Accordingly, unrealized gains and losses are deferred in regulatory liabilities and assets and net income is not impacted.

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments: the fair values of cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at March 31, 2019 and December 31, 2018, as they are short-term in nature or have interest rates that reset daily.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

	At March 31, 2019		At December 31, 2018	
(in millions)	**Carrying Amount**	**Level 2 Fair Value**	**Carrying Amount**	**Level 2 Fair Value**
PG&E Corporation[(1)]	—	—	$ 350	$ 350
Utility[(1)(2)]	350	350	17,450	14,747

(1) On January 29, 2019 PG&E Corporation and the Utility filed for Chapter 11 protection. Debt held by PG&E Corporation and the Utility became debt subject to compromise and is valued at the allowed claim amount. For more information, see Note 2 and Note 4.
(2) The Utility drew $350 million from the DIP Revolving Facility on February 1, 2019 which was subsequently repaid on April 3, 2019 using certain of the proceeds of the DIP Initial Term Loan Facility.

Nuclear Decommissioning Trust Investments

The following table provides a summary of equity securities and available-for-sale debt securities:

(in millions) As of March 31, 2019	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
Nuclear decommissioning trusts				
Short-term investments	$ 18	$ —	$ —	$ 18
Global equity securities	481	1,422	(3)	1,900
Fixed-income securities	1,432	58	(8)	1,482
Total [(1)]	**$ 1,931**	**$ 1,480**	**$ (11)**	**$ 3,400**
As of December 31, 2018				
Nuclear decommissioning trusts				
Short-term investments	$ 29	$ —	$ —	$ 29
Global equity securities	568	1,246	(5)	1,809
Fixed-income securities	1,288	30	(18)	1,300
Total [(1)]	**$ 1,885**	**$ 1,276**	**$ (23)**	**$ 3,138**

[(1)] Represents amounts before deducting $468 million and $408 million for the periods ended March 31, 2019 and December 31, 2018, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of fixed-income securities by contractual maturity is as follows:

(in millions)	As of March 31, 2019
Less than 1 year	$ 31
1–5 years	534
5–10 years	337
More than 10 years	580
Total maturities of fixed-income securities	**$ 1,482**

The following table provides a summary of activity for fixed income and equity securities:

(in millions)	Three Months Ended March 31, 2019	2018
Proceeds from sales and maturities of nuclear decommissioning trust investments	$ 346	$ 494
Gross realized gains on securities	(34)	37
Gross realized losses on securities	19	(4)

NOTE 10: WILDFIRE-RELATED CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to wildfires. A provision for a loss contingency is recorded when it is both probable that a liability has been incurred and the amount of the liability can be reasonably estimated. PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses and record a charge that reflects their best estimate or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows may be materially affected by the outcome of the following matters.

Wildfire-Related Claims

Wildfire-related claims on the Condensed Consolidated Financial Statements include amounts associated with the 2018 Camp fire, the 2017 Northern California wildfires, and the 2015 Butte fire.

For the three months ended March 31, 2019 and 2018, the Utility's Condensed Consolidated Statements of Income include estimated losses offset by insurance recoveries of $7 million for the three months ended March 31, 2018, with no recoveries in the same period in 2019.

In addition, during the three months ended March 31, 2019, the Utility incurred $13 million and $34 million of legal and other costs related to the 2018 Camp fire and the 2017 Northern California wildfires, respectively.

At March 31, 2019 and December 31, 2018, the Utility's Condensed Consolidated Balance Sheets include estimated liabilities in respect of total wildfire-related claims as follows:

	Balance at	
(in millions)	**March 31, 2019**	**December 31, 2018**
2015 Butte fire	$ 212	$ 226
2017 Northern California wildfires	3,500	3,500
2018 Camp fire	10,500	10,500
Total wildfire-related claims [(1)]	**$ 14,212**	**$ 14,226**

(1) On the Petition Date all wildfire-related claims were classified as subject to compromise and all pending litigation was stayed. (For more information see Note 2 of the Condensed Consolidated Financial Statements.)

2018 Camp Fire Background

On November 8, 2018, a wildfire began near the city of Paradise, Butte County, California (the "2018 Camp fire"), which is located in the Utility's service territory. Cal Fire's Camp Fire Incident Information Website as of January 4, 2019 (the "Cal Fire website") indicated that the 2018 Camp fire consumed 153,336 acres. On the Cal Fire website, Cal Fire reported 86 fatalities and the destruction of 13,972 residences, 528 commercial structures and 4,293 other buildings resulting from the 2018 Camp fire. On February 7, 2019, the Butte County Sheriff's Office reported that the number of fatalities resulting from the 2018 Camp fire had been reduced from 86 to 85. There have been no subsequent updates of this information on the Cal Fire website or by the Butte County Sheriff's Office.

Although the cause of the 2018 Camp fire is still under investigation, based on the information currently known to PG&E Corporation and the Utility and reported to the CPUC and other agencies, including the facts described below, PG&E Corporation and the Utility believe it is probable that the Utility's equipment will be determined to be an ignition point of the 2018 Camp fire.

The Utility submitted two Electric Incident Reports (the "EIRs") to the CPUC: one on November 8, 2018 and one on November 16, 2018. On December 11, 2018, the Utility publicly released a letter to the CPUC supplementing the EIRs (the "20-Day Electric Incident Report"), which stated:

- On the Cal Fire website, Cal Fire has identified coordinates for the 2018 Camp fire near Tower :27/222 on the Utility's Caribou-Palermo 115 kV Transmission Line and has identified the start time of the 2018 Camp fire as 6:33 a.m. on November 8, 2018.

- On November 8, 2018, at approximately 6:15 a.m., the Utility's Caribou-Palermo 115kV Transmission Line relayed and deenergized. At approximately 6:30 a.m. that day, a Utility employee observed fire in the vicinity of Tower :27/222, and this observation was reported to 911 by Utility employees. That afternoon, the Utility observed damage on the line at Tower :27/222. Specifically, an aerial patrol identified that a suspension insulator supporting a transposition jumper had separated from an arm on Tower :27/222.

- On November 14, 2018, the Utility observed a broken C-hook attached to the separated suspension insulator that had connected the suspension insulator to a tower arm, along with wear at the connection point. In addition, the Utility observed a flash mark on Tower :27/222 near where the transposition jumper was suspended and damage to the transposition jumper and suspension insulator.

- In addition to the events on the Caribou-Palermo 115kV Transmission Line, on November 8, 2018, at approximately 6:45 a.m., the Utility's Big Bend 1101 12 kV Circuit experienced an outage. On November 9, 2018, a Utility employee on patrol arrived at the location of the pole with Line Recloser ("LR") 1704 on the Big Bend 1101 Circuit and observed that the pole and other equipment were on the ground with bullets and bullet holes at the break point of the pole and on the equipment. On November 12, 2018, a Utility employee was patrolling Concow Road north of LR 1704 when he observed wires down and damaged and downed poles at the intersection of Concow Road and Rim Road. At this location, the employee observed several snapped trees, with some on top of the downed wires.

The information contained in the EIRs and the 20-Day Electric Incident Report is factual and preliminary and does not reflect a determination of the causes of the 2018 Camp fire. These incidents remain under investigation by Cal Fire and the CPUC. With respect to the potential ignition point on the Utility's Big Bend 1101 12 kV Circuit, although Cal Fire has identified this location as a potential ignition point, based on the condition of the site, PG&E Corporation and the Utility have not been able to determine whether the Big Bend 1101 12 kV Circuit may be a probable ignition point for the 2018 Camp fire. Neither Cal Fire nor the CPUC has publicly issued any news releases or other determinations for the 2018 Camp fire. The timing and outcome of the investigations are uncertain. PG&E Corporation and the Utility are cooperating with Cal Fire and the CPUC.

Further, the CPUC's SED is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire-impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating the fire. It is uncertain when the investigations will be complete and whether the SED will release any preliminary findings before its investigations are complete.

2017 Northern California Wildfires Background

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City (the "2017 Northern California wildfires"). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the 2017 Northern California wildfires, there were 21 major fires that, in total, burned over 245,000 acres and destroyed an estimated 8,900 structures. The 2017 Northern California wildfires resulted in 44 fatalities.

Cal Fire has issued its determination on the causes of 19 of the 2017 Northern California wildfires, and alleged that all of these fires, with the exception of the Tubbs fire, involved the Utility's equipment. Cal Fire has not publicly announced any determination of cause on the remaining wildfires.

During the second quarter of 2018, Cal Fire issued news releases announcing its determination on the causes of 16 of the 2017 Northern California wildfires (the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket and Atlas fires, located in Mendocino, Lake, Butte, Sonoma, Humboldt, Nevada and Napa counties). According to the Cal Fire news releases:

- the La Porte, McCourtney, Lobo and Honey fires "were caused by trees coming into contact with power lines", and
- the Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket and Atlas fires "were caused by electric power and distribution lines, conductors and the failure of power poles."

Cal Fire has not yet released its investigation reports related to the McCourtney, Lobo, Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires and stated in its news releases that these investigations, and the investigation related to the Honey fire, have been referred to the appropriate county District Attorney's offices for review "due to evidence of alleged violations of state law." (See "District Attorneys' Offices' Investigations" below for further information regarding the investigations by the District Attorneys' offices related to these fires.)

Also during the second quarter of 2018, Cal Fire released its investigation reports related to the Redwood, Cherokee, 37, Nuns and La Porte fires. Cal Fire did not refer these fires to District Attorney offices for investigation.

On October 9, 2018, Cal Fire issued a news release announcing the results of its investigation into the Cascade fire, located in Yuba County, concluding that the Cascade fire "was started by sagging power lines coming into contact during heavy winds" and that "the power line in question was owned by Pacific Gas and Electric Company." On October 10, 2018, Cal Fire released its investigation report related to the Cascade fire. (See "District Attorneys' Offices' Investigations" below for further information regarding the investigations of the Cascade fire by the Office of the District Attorney of Yuba County.)

On January 24, 2019, Cal Fire issued a news release and its investigation report into the cause of the Tubbs fire. Cal Fire has determined that the Tubbs fire was caused by a private electrical system adjacent to a residential structure.

Cal Fire has not publicly issued any news releases or other determinations for the Maacama, Pressley and Point wildfires. The timing and outcome of the Cal Fire investigation into these fires is uncertain.

Further, the SED is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire-impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating certain of the fires. It is uncertain when the investigations will be complete and whether the SED will release any preliminary findings before its investigations are complete.

The Utility has submitted 23 electric incident reports to the CPUC associated with the 2017 Northern California wildfires where Cal Fire or the Utility has identified a site as potentially involving the Utility's facilities in its investigation and the property damage associated with each incident exceeded $50,000. The information contained in these reports is factual and preliminary and does not reflect a determination of the causes of the fires.

Third-Party Claims, Investigations and Other Proceedings Related to the 2018 Camp Fire and 2017 Northern California Wildfires

If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the substantial cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, business interruption, interest and attorneys' fees without having been found negligent. California courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefited from such undertaking, and based on the assumption that utilities have the ability to recover these costs from their customers. Further, California courts have determined that the doctrine of inverse condemnation is applicable regardless of whether the CPUC ultimately allows recovery by the utility for any such costs. The CPUC may decide not to authorize cost recovery even if a court decision were to determine that the Utility is liable as a result of the application of the doctrine of inverse condemnation. (See "Loss Recoveries-Regulatory Recovery" below for further information regarding potential cost recovery related to the wildfires, including in connection with SB 901.)

In addition to claims for property damage, business interruption, interest and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, punitive damages and other damages under other theories of liability, including if the Utility were found to have been negligent.

Further, the Utility could be subject to material fines, penalties, or restitution orders if the CPUC or any law enforcement agency were to bring an enforcement action, including a criminal proceeding, and it were determined that the Utility had failed to comply with applicable laws and regulations.

As of January 28, 2019, PG&E Corporation and the Utility are aware of approximately 100 complaints on behalf of at least 4,200 plaintiffs related to the 2018 Camp fire, nine of which seek to be certified as class actions. The pending civil litigation against PG&E Corporation and the Utility related to the 2018 Camp fire, which is currently stayed as a result of the commencement of the Chapter 11 Cases, includes claims under multiple theories of liability, including inverse condemnation, trespass, private nuisance, public nuisance, negligence, negligence per se, negligent interference with prospective economic advantage, negligent infliction of emotional distress, premises liability, violations of the Public Utilities Code, violations of the Health & Safety Code, malice and false advertising in violation of the California Business and Professions Code. The plaintiffs principally assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the 2018 Camp fire. The plaintiffs seek damages and remedies that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, establishment of a class action medical monitoring fund, punitive damages, attorneys' fees and other damages. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

As of January 28, 2019, PG&E Corporation and the Utility are aware of approximately 750 complaints on behalf of at least 3,800 plaintiffs related to the 2017 Northern California wildfires, five of which seek to be certified as class actions. These cases have been coordinated in the San Francisco County Superior Court. As of the Petition Date, the coordinated litigation was in the early stages of discovery. A trial with respect to the Atlas fire was scheduled to begin on September 23, 2019. The pending civil litigation against PG&E Corporation and the Utility related to the 2017 Northern California wildfires, includes claims under multiple theories of liability, including inverse condemnation, trespass, private nuisance and negligence. This litigation, including the trial date with respect to the Atlas fire, currently is stayed as a result of the commencement of the Chapter 11 Cases. The plaintiffs principally assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the 2017 Northern California wildfires. The plaintiffs seek damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees and other damages. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

Insurance carriers who have made payments to their insureds for property damage arising out of the 2017 Northern California wildfires have filed 52 subrogation complaints in the San Francisco County Superior Court and the Sonoma County Superior Court as of January 28, 2019. These complaints allege, among other things, negligence, inverse condemnation, trespass and nuisance. The allegations are similar to the ones made by individual plaintiffs. As of January 28, 2019, insurance carriers have filed 39 similar subrogation complaints with respect to the 2018 Camp fire in the Sacramento County Superior Court and the Butte County Superior Court. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

Various government entities, including Yuba, Nevada, Lake, Mendocino, Napa and Sonoma Counties and the Cities of Santa Rosa and Clearlake, also have asserted claims against PG&E Corporation and the Utility based on the damages that these government entities allegedly suffered as a result of the 2017 Northern California wildfires. Such alleged damages include, among other things, loss of natural resources, loss of public parks, property damages and fire suppression costs. The causes of action and allegations are similar to the ones made by individual plaintiffs and the insurance carriers. With respect to the 2018 Camp fire, Butte County has filed similar claims against PG&E Corporation and the Utility, and PG&E Corporation and the Utility expect additional similar claims to be made by other government entities. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

On March 16, 2018, PG&E Corporation and the Utility filed a demurrer to the inverse condemnation cause of action in the 2017 Northern California wildfires litigation. On May 21, 2018, the court overruled the motion. On July 20, 2018, PG&E Corporation and the Utility filed a writ in the Court of Appeal requesting appellate review of the trial court's decision, which was denied on September 17, 2018. On September 27, 2018, PG&E Corporation and the Utility filed a petition for review to the California Supreme Court. On November 14, 2018, the California Supreme Court denied PG&E Corporation's and the Utility's petition for review.

PG&E Corporation and the Utility expect to be the subject of numerous additional claims in connection with the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

PG&E Corporation and the Utility are continuing to review the evidence concerning the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation and the Utility have not yet had access to all of the evidence collected by Cal Fire as part of its investigations or to many of the investigation reports prepared by Cal Fire. PG&E Corporation and the Utility and plaintiffs are in discussions with Cal Fire about access to the evidence and the remaining reports. No schedule on gaining access has been set. (See "District Attorneys' Offices' Investigations" below for information regarding certain investigations related to the 2018 Camp fire and 2017 Northern California wildfires.)

Regardless of any determinations of cause by Cal Fire with respect to any pre-petition fire, ultimately PG&E Corporation's and the Utility's liability will be resolved through the Chapter 11 process, regulatory proceedings and any potential enforcement proceedings, all of which could take a number of years to resolve. The timing and outcome of these and other potential proceedings are uncertain.

PG&E Corporation and the Utility, as part of their efforts to emerge from bankruptcy, are engaged in discussions with holders of claims related to the 2017 Northern California wildfires and the 2018 Camp Fire in an attempt to reach a global settlement of such claims. PG&E Corporation and the Utility cannot predict the outcome or timing of such discussions. Even if discussions with claimholders were successful, the consummation of such an agreement would likely be contingent on numerous uncertain conditions, including Bankruptcy Court approval and governmental action.

Potential Losses in Connection with the 2018 Camp Fire and 2017 Northern California Wildfires

On January 28, 2019, the California Department of Insurance issued a news release announcing an update on property losses in connection with the 2018 wildfires in Southern California (which are not in the Utility's service territory) and the 2018 Camp fire, stating that, as of such date, "more than $11.4 billion in insured losses have been reported from the November 2018 fires," of which approximately $8.4 billion relates to statewide claims from the 2018 Camp fire. On September 6, 2018, the California Department of Insurance issued a news release announcing that insurers have received nearly 55,000 insurance claims totaling more than $12.28 billion in losses, of which approximately $10 billion relates to statewide claims from the 2017 Northern California wildfires.

The dollar amounts announced by the California Department of Insurance represent an aggregate amount of approximately $18.4 billion of insurance claims made as of the above dates related to the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation and the Utility expect that additional claims have been submitted and will continue to be submitted to insurers, particularly with respect to the 2018 Camp fire. These claims reflect insured property losses only. The $18.4 billion of insurance claims made as of the above dates does not account for uninsured or underinsured property losses, interest, attorneys' fees, fire suppression and clean-up costs, evacuation costs, personal injury or wrongful death damages, medical expenses or other costs, such as potential punitive damages, fines or penalties, or losses related to claims that have not manifested yet ("future claims"), each of which could be significant. The scope of all claims related to the 2018 Camp fire and 2017 Northern California wildfires is not known at this time because of the applicable statutes of limitations under California law.

Potential liabilities related to the 2018 Camp fire and 2017 Northern California wildfires depend on various factors, including but not limited to the cause of each fire, contributing causes of the fires (including alternative potential origins, weather and climate related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, including the loss of lives, the extent to which future claims arise, the amount of fire suppression and clean-up costs, other damages the Utility may be responsible for if found negligent, the amount of any penalties or fines that may be imposed by governmental entities, and the amount of any penalties, fines, or restitution orders that might result from any criminal charges brought.

There are a number of unknown facts and legal considerations that may impact the amount of any potential liability. Among other things, it is uncertain at this time as to the number of wildfire-related claims that will be filed in the Chapter 11 Cases, the number of current and future claims that will be allowed by the Bankruptcy Court, how claims for punitive damages and claims by variously situated persons will be treated and whether such claims will be allowed, and the impact that historical settlement values for wildfire claims may have on the estimation of wildfire liability in the Chapter 11 Cases. If PG&E Corporation and the Utility were to be found liable for certain or all of the costs, expenses and other losses described above with respect to the 2018 Camp fire and 2017 Northern California wildfires, the amount of such liability could exceed $30 billion, which amount does not include potential punitive damages, fines and penalties or damages related to future claims. This estimate is based on a wide variety of data and other information available to PG&E Corporation and the Utility and their advisors, including various precedents involving similar claims, and accounts for property losses (including insured, uninsured and underinsured property losses), interest, attorneys' fees, fire suppression and clean-up costs, evacuation costs, personal injury or wrongful death damages, medical expenses and certain other costs. This estimate is not intended to provide an upper end of the range of potential liability arising from the 2018 Camp fire and 2017 Northern California wildfires. In certain circumstances, PG&E Corporation's and the Utility's liability could be substantially greater than such amount.

If PG&E Corporation and the Utility were to be found liable for any punitive damages or subject to fines or penalties, the amount of such punitive damages, fines and penalties could be significant. PG&E Corporation and the Utility have received significant fines and penalties in connection with past incidents. For example, in 2015, the CPUC approved a decision that imposed penalties on the Utility totaling $1.6 billion in connection with the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010 (the "San Bruno explosion"). These penalties represented nearly three times the underlying liability for the San Bruno explosion of approximately $558 million incurred for third-party claims, exclusive of shareholder derivative lawsuits and legal costs incurred. The amount of punitive damages, fines and penalties imposed on PG&E Corporation and the Utility could likewise be a significant amount in relation to the underlying liabilities with respect to the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process. Such proceedings are not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases; however, collection efforts in connection with fines or penalties arising out of such proceedings are stayed.

2018 Camp Fire and 2017 Northern California Wildfires Accounting Charge

Following accounting rules, PG&E Corporation and the Utility record a liability when a loss is probable and reasonably estimable. In accordance with U.S. generally accepted accounting principles, PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses, and record a charge that is the amount within the range that is a better estimate than any other amount or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events.

2018 Camp Fire

In light of the current state of the law and the information currently available to the Utility, including, among other things, the facts described in the EIRs and the 20-Day Electric Incident Report, PG&E Corporation and the Utility have determined that it is probable they will incur a loss for claims in connection with the 2018 Camp fire, and accordingly PG&E Corporation and the Utility recorded a charge in the amount of $10.5 billion for the year ended December 31, 2018. This charge corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimated losses, and is subject to change based on additional information.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss related to the 2018 Camp fire and 2017 Northern California wildfires will be greater than the amount accrued, but are unable to reasonably estimate the additional loss and the upper end of the range because there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in Cal Fire's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of personal and business property damage and losses, the nature, number and severity of personal injuries, and information made available through the discovery process.

The process for estimating losses associated with claims requires management to exercise significant judgment based on a number of assumptions and subjective factors, including but not limited to factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the financial impact of the 2018 Camp fire may change, which could result in material increases to the loss accrued.

The $10.5 billion charge does not include any amounts for potential penalties or fines that may be imposed by governmental entities on PG&E Corporation or the Utility, or punitive damages, if any, or any losses related to future claims for damages that have not manifested yet, each of which could be significant.

2017 Northern California Wildfires

In light of the current state of the law on inverse condemnation and the information currently available to the Utility, including, among other things, the Cal Fire determinations of cause as stated in Cal Fire's press releases and their released reports, PG&E Corporation and the Utility have determined that it is probable they will incur a loss for claims in connection with 17 of the 2017 Northern California wildfires referred to as the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, Blue, Pocket, Atlas, Cascade, Point and Sonoma/Napa merged fires (which include the Nuns, Norrbom, Adobe, Partrick and Pythian fires). Accordingly, PG&E Corporation and the Utility recorded a charge in the amount of $2.5 billion during the quarter ended June 30, 2018 and a charge in the amount of $1.0 billion during the quarter ended December 31, 2018, for a total charge in the amount of $3.5 billion for the year ended December 31, 2018. This charge corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimated losses and is subject to change based on additional information.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss related to the 2017 Northern California wildfires and the 2018 Camp fire will be greater than the amount accrued, but are unable to reasonably estimate the additional loss and the upper end of the range because there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in Cal Fire's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of personal and business property damage and losses, the nature, number and severity of personal injuries, and information made available through the discovery process.

The process for estimating losses associated with claims requires management to exercise significant judgment based on a number of assumptions and subjective factors, including but not limited to factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the financial impact of the 2017 Northern California wildfires may change, which could result in material increases to the loss accrued.

The $3.5 billion charge does not include any amounts for potential penalties or fines that may be imposed by governmental entities on PG&E Corporation or the Utility, or punitive damages, if any, or any losses related to future claims for damages that have not manifested yet, each of which could be significant.

The $3.5 billion charge also does not include any amounts in connection with the 37, Tubbs, Maacama and Pressley fires because at this time PG&E Corporation and the Utility have not concluded that a loss arising from those fires is probable. However, in the future it is possible that facts could emerge that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in the accrual of a liability at that time, the amount of which could be significant.

Loss Recoveries

PG&E Corporation and the Utility had insurance coverage for liabilities, including wildfire. Additionally, there are several mechanisms that allow for recovery of costs from customers. Potential for recovery is described below. Failure to obtain a substantial or full recovery of costs related to the 2018 Camp fire and 2017 Northern California wildfires or any conclusion that such recovery is no longer probable could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. In addition, the inability to recover costs in in a timely manner could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Insurance

PG&E Corporation and the Utility had $842 million of insurance coverage for liabilities, including wildfire events, for the period from August 1, 2017 through July 31, 2018, subject to an initial self-insured retention of $10 million per occurrence and further retentions of approximately $40 million per occurrence. During the third quarter of 2018, PG&E Corporation and the Utility renewed their liability insurance coverage for wildfire events in an aggregate amount of approximately $1.4 billion for the period from August 1, 2018 through July 31, 2019, comprised of $700 million for general liability (subject to an initial self-insured retention of $10 million per occurrence), and $700 million for property damages only, which property damage coverage includes an aggregate amount of approximately $200 million through the reinsurance market where a catastrophe bond was utilized. PG&E Corporation and the Utility expect to face increasing difficulty securing liability insurance in future years due to availability and to face significantly increased insurance costs.

PG&E Corporation and the Utility record a receivable for insurance recoveries when it is deemed probable that recovery of a recorded loss will occur. Through March 31, 2019, PG&E Corporation and the Utility recorded $1.38 billion for probable insurance recoveries in connection with the 2018 Camp fire and $842 million for probable insurance recoveries in connection with the 2017 Northern California wildfires. These amounts reflect an assumption that the cause of each fire is deemed to be a separate occurrence under the insurance policies. The amount of the receivable is subject to change based on additional information. PG&E Corporation and the Utility intend to seek full recovery for all insured losses and believe it is reasonably possible that they will record a receivable for the full amount of the insurance limits in the future.

If PG&E Corporation and the Utility are unable to recover the full amount of their insurance, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected. Even if PG&E Corporation and the Utility were to recover the full amount of their insurance, PG&E Corporation and the Utility expect their losses in connection with the 2018 Camp fire and 2017 Northern California wildfires will substantially exceed their available insurance.

The following table presents changes in the insurance receivable for the three months ended March 31, 2019. The balance for insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets:

(in millions)		**Insurance Receivable**
2018 Camp fire		
Balance at December 31, 2018	**$**	**1,380**
Accrued insurance recoveries	$	—
Reimbursements		—
Balance at March 31, 2019	**$**	**1,380**
2017 Northern California wildfires		
Balance at December 31, 2018	**$**	**829**
Accrued insurance recoveries		—
Reimbursements		—
Balance at March 31, 2019	**$**	**829**

Regulatory Recovery

On June 21, 2018, the CPUC issued a decision granting the Utility's request to establish a WEMA to track specific incremental wildfire liability costs effective as of July 26, 2017. The decision does not grant the Utility rate recovery of any wildfire-related costs. Any such rate recovery would require CPUC authorization in a separate proceeding. The Utility may be unable to fully recover costs in excess of insurance, if at all. Rate recovery is uncertain, therefore the Utility has not recorded a regulatory asset related to any wildfire claims costs. Even if such recovery is possible, it could take a number of years to resolve and a number of years to collect.

In addition, SB 901, signed into law on September 21, 2018, requires the CPUC to establish a customer harm threshold, directing the CPUC to limit certain disallowances in the aggregate, so that they do not exceed the maximum amount that the Utility can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service (the "Customer Harm Threshold"). SB 901 also authorizes the CPUC to issue a financing order that permits recovery, through the issuance of recovery bonds (also referred to as "securitization"), of wildfire-related costs found to be just and reasonable by the CPUC and, only for the 2017 Northern California wildfires, any amounts in excess of the Customer Harm Threshold. SB 901 does not authorize securitization with respect to possible 2018 Camp fire costs.

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the Customer Harm Threshold in future applications under Section 451.2(a) of the Public Utilities Code for cost recovery of 2017 wildfire costs. In the OIR, the CPUC stated that "consistent with Section 451.2(a), the determination of what costs and expenses are just and reasonable must be made in the context of an application for the recovery of specific costs related to the 2017 wildfires." Following the CPUC's interpretation of Section 451.2 as outlined in the OIR, PG&E Corporation and the Utility believe that any securitization of costs relating to the 2017 Northern California wildfires would not occur, if at all, until (a) the Utility has paid claims relating to the 2017 Northern California wildfires, (b) the Utility has filed application for recovery of such costs and (c) the CPUC makes a determination that such costs are just and reasonable or in excess of the Customer Harm Threshold. PG&E Corporation and the Utility therefore do not expect the CPUC to permit the Utility to securitize costs relating to the 2017 Northern California wildfires on an expedited or emergency basis unless the CPUC alters the position expressed in the OIR.

On February 11, 2019, the Utility filed opening comments in response to the OIR in which it argued, among other things, the CPUC should (1) promptly set a Customer Harm Threshold, or at least define the methodology for setting the Customer Harm Threshold with sufficient specificity to enable PG&E Corporation and the Utility and potential investors to anticipate that amount; (2) determine the Customer Harm Threshold based on the capital needed to resolve claims arising from both the 2018 Camp fire and 2017 Northern California wildfires to be provided for in a plan of reorganization; (3) define how the Customer Harm Threshold will be applied to any future wildfires; and (4) establish the Customer Harm Threshold based on the amount of debt the Utility can raise while maintaining investment grade credit ratings, which it estimates to be approximately $3 billion.

On March 29, 2019, the Assigned Commissioner issued a Scoping Memo, which stated that the CPUC in this proceeding will establish a Customer Harm Threshold methodology applicable only to 2017 fires, to be invoked in connection with a future application for cost recovery, and will not determine a specific financial outcome in this proceeding.

On April 5, 2019, the Assigned Commissioner published a Staff Report, describing a proposed stress test to determine the Customer Harm Threshold based on: (1) the maximum additional debt that a utility can take on and maintain a minimum investment-grade credit rating; (2) excess cash available to the utility; and (3) a potential regulatory adjustment upward or downward by a maximum of 20%, to be determined by the CPUC. If a utility is already at or below a minimum investment-grade credit rating, and the calculation of the Customer Harm Threshold based on maximum additional debt that the utility can take on plus the excess cash available to the utility is very low or zero, the Staff Report contemplates a different standard for the potential regulatory adjustment: upward or downward adjustment by a maximum of 5% of the total disallowed wildfire liability. The Staff Report also proposed two "optional concepts" for ratepayer protection: (1) a de-escalation of the utility's authorized return on equity based on the amount of customer costs in excess of the Customer Harm Threshold, capped at 300 basis points, and (2) equity warrants in favor of customers in the amount of 1% for every $500 million of securitized wildfire liability, capped at 15%. On April 10, 2019, a workshop addressing the Staff Report was held. On April 12, 2019, the Assigned Commissioner extended the time for parties to file comments on the Staff Report, to April 24, 2019 for opening comments and May 1, 2019 for reply comments.

Failure to obtain a substantial or full recovery of costs related to the 2018 Camp fire and 2017 Northern California wildfires or any conclusion that such recovery is no longer probable could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows.

Wildfire-Related Derivative Litigation

Two purported derivative lawsuits alleging claims for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively, naming as defendants current and certain former members of the Board of Directors and certain current and former officers of PG&E Corporation and the Utility. PG&E Corporation and the Utility are named as nominal defendants. These lawsuits were consolidated by the court on February 14, 2018, and are denominated *In Re California North Bay Fire Derivative Litigation*. On April 13, 2018, the plaintiffs filed a consolidated complaint. After the parties reached an agreement regarding a stay of the derivative proceeding pending resolution of the tort actions described above and any regulatory proceeding relating to the 2017 Northern California wildfires, on April 24, 2018, the court entered a stipulation and order to stay. The stay is subject to certain conditions regarding the plaintiffs' access to discovery in other actions. On January 28, 2019, the plaintiffs filed a request to lift the stay for the purposes of amending their complaint to add allegations regarding the 2018 Camp fire.

On August 3, 2018, a third purported derivative lawsuit, entitled *Oklahoma Firefighters Pension and Retirement System v. Chew, et al.*, was filed in the U.S. District Court for the Northern District of California, naming as defendants certain current and former members of the Board of Directors and certain current and former officers of PG&E Corporation and the Utility. PG&E Corporation is named as a nominal defendant. The lawsuit alleges claims for breach of fiduciary duties and unjust enrichment as well as a claim under Section 14(a) of the federal Securities Exchange Act of 1934 alleging that PG&E Corporation's and the Utility's 2017 proxy statement contained misrepresentations regarding the companies' risk management and safety programs. On October 15, 2018, PG&E Corporation filed a motion to stay the litigation. Prior to the scheduled hearing on this motion, this matter was automatically stayed by PG&E Corporation's and the Utility's commencement of bankruptcy proceedings, as discussed below.

On October 23, 2018, a fourth purported derivative lawsuit, entitled *City of Warren Police and Fire Retirement System v. Chew, et al.*, was filed in San Francisco County Superior Court, alleging claims for breach of fiduciary duty, corporate waste and unjust enrichment. It names as defendants certain current and former members of the Board of Directors and certain current and former officers of PG&E Corporation, and names PG&E Corporation as a nominal defendant. Plaintiff filed a request with the court seeking the voluntary dismissal of this matter without prejudice on January 18, 2019.

On November 21, 2018, a fifth purported derivative lawsuit, entitled *Williams v. Earley, Jr., et al.*, was filed in federal court in San Francisco, alleging claims identical to those alleged in the *Oklahoma Firefighters Pension and Retirement System v. Chew, et al.* lawsuit listed above against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. This lawsuit includes allegations related to the 2017 Northern California wildfires and the 2018 Camp fire. This action was stayed by stipulation of the parties and order of the court on December 21, 2018, subject to resolution of the pending securities class action.

On December 24, 2018, a sixth purported derivative lawsuit, entitled *Bowlinger v. Chew, et al.*, was filed in San Francisco Superior Court, alleging claims for breach of fiduciary duty, abuse of control, corporate waste, and unjust enrichment in connection with the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. The court has scheduled a case management conference for December 13, 2019.

On January 25, 2019, a seventh purported derivative lawsuit, entitled *Hagberg v. Chew, et al.*, was filed in San Francisco Superior Court, alleging claims for breach of fiduciary duty, abuse of control, corporate waste, and unjust enrichment in connection with the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants.

On January 28, 2019, an eighth purported derivative lawsuit, entitled *Blackburn v. Meserve, et al.*, was filed in federal court alleging claims for breach of fiduciary duty, unjust enrichment, and waste of corporate assets in connection with the 2017 Northern California wildfires and the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation as a nominal defendant.

Due to the commencement of the Chapter 11 Cases, PG&E Corporation and the Utility filed notices in each of these proceedings on February 1, 2019, reflecting that the proceedings are automatically stayed pursuant to Section 362(a) of the Bankruptcy Code. On February 5, 2019, the plaintiff in *Bowlinger v. Chew, et al.* filed a response to the notice asserting that the automatic stay did not apply to his claims. PG&E Corporation and the Utility accordingly filed a Motion to Enforce the Automatic Stay with the Bankruptcy Court as to the *Bowlinger* action, which was granted.

Wildfire-Related Securities Class Action Litigation

In June 2018, two purported securities class actions were filed in the United States District Court for the Northern District of California, naming PG&E Corporation and certain of its current and former officers as defendants, entitled *David C. Weston v. PG&E Corporation, et al.* and *Jon Paul Moretti v. PG&E Corporation, et al.*, respectively. The complaints alleged material misrepresentations and omissions related to, among other things, vegetation management and transmission line safety in various PG&E Corporation public disclosures. The complaints asserted claims under Section 10(b) and Section 20(a) of the federal Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder, and sought unspecified monetary relief, interest, attorneys' fees and other costs. Both complaints identified a proposed class period of April 29, 2015 to June 8, 2018. On September 10, 2018, the court consolidated both cases and the litigation is now denominated *In re PG&E Corporation Securities Litigation*. The court also appointed the Public Employees Retirement Association of New Mexico as lead plaintiff. The plaintiff filed a consolidated amended complaint on November 9, 2018. After the plaintiff requested leave to amend their complaint to add allegations regarding the 2018 Camp fire, the plaintiff filed a second amended consolidated complaint on December 14, 2018.

Due to the commencement of the Chapter 11 Cases, PG&E Corporation and the Utility filed a notice on February 1, 2019, reflecting that the proceedings are automatically stayed pursuant to Section 362(a) of the Bankruptcy Code. On February 15, 2019, PG&E Corporation and the Utility filed a complaint in Bankruptcy Court against the plaintiff seeking preliminary and permanent injunctive relief to extend the stay to the claims alleged against the individual officer defendants.

On February 22, 2019, a purported securities class action was filed in the United States District Court for the Northern District of California, entitled *York County on behalf of the York County Retirement Fund, et al. v. Rambo, et al* (the "York County Action"). The complaint names as defendants certain current and former officers and directors, as well as the underwriters of four public offerings of notes from 2016 to 2018. Neither PG&E Corporation nor the Utility is named as a defendant. The complaint alleges material misrepresentations and omissions in connection with the note offerings related to, among other things, PG&E Corporation's and the Utility's vegetation management and wildfire safety measures. The complaint asserts claims under Section 11 and Section 15 of the federal Securities Act of 1933, and seeks unspecified monetary relief, attorneys' fees and other costs, and injunctive relief.

District Attorneys' Offices' Investigations

During the second quarter of 2018, Cal Fire issued news releases stating that it referred the investigations related to the McCourtney, Lobo, Honey, Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires to the appropriate county District Attorney's offices for review "due to evidence of alleged violations of state law." On March 12, 2019, the Sonoma, Napa, Humboldt and Lake County District Attorneys announced that they would not prosecute PG&E Corporation or the Utility for the fires in those counties, which include the Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires.

PG&E Corporation and the Utility are the subject of criminal investigations or other actions by the Nevada County District Attorney's Office to whom Cal Fire has referred its investigations into the McCourtney and Lobo fires. In October 2018, the Utility and the Nevada County District Attorney entered into an agreement under which the Utility agreed to waive any applicable statutes of limitation related to the two wildfires that started in that county for a period of six months until April 8, 2019. In March 2019, the Utility and the Nevada County District Attorney extended that agreement for an additional six months, to October 8, 2019. PG&E Corporation and the Utility anticipate further discussions with the Nevada County District Attorney relating to the two wildfires that started in that county and whether any criminal charges should be brought.

The Honey fire was referred to the Butte County District Attorney's Office, and in October 2018, the Utility reached an agreement to settle any civil claims or criminal charges that could have been brought by the Butte County District Attorney in connection with the Honey fire, as well as the La Porte and Cherokee fires (which were not referred). The settlement provides for funding by the Utility for at least four years of an enhanced fire prevention and communication program, in the amount of up to $1.5 million, not recoverable in rates.

On October 9, 2018, the Office of the District Attorney of Yuba County announced its decision not to pursue criminal charges at such time against PG&E Corporation or the Utility pertaining to the Cascade fire. The District Attorney's Office also indicated that it reserved the right "to review any additional information or evidence that may be submitted to it prior to the expiration of the criminal statute of limitations."

In addition, the Butte County District Attorney's Office and the California Attorney General's Office have opened a criminal investigation of the 2018 Camp fire. PG&E Corporation and the Utility have been informed by the Butte County District Attorney's Office and the California Attorney General's Office that a grand jury has been empaneled in Butte County, and the Utility was served with subpoenas in the grand jury investigation. The Utility has produced documents and continues to produce documents in connection with the criminal investigation of the 2018 Camp fire, including, but not limited to, documents related to the operation and maintenance of equipment owned or operated by the Utility. The Utility has also cooperated with the Butte County District Attorney's Office and the California Attorney General's Office in the collection of physical evidence from equipment owned or operated by the Utility. PG&E Corporation and the Utility are unable to predict the outcome of the criminal investigation into the 2018 Camp fire. The Utility could be subject to material fines, penalties, or restitution order if it is determined that the Utility failed to comply with applicable laws and regulations, as well as non-monetary remedies such as oversight requirements. The criminal investigation is not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases.

Additional investigations and other actions may arise out of the other 2017 Northern California wildfires and the 2018 Camp fire. The timing and outcome for resolution of the remaining referrals by Cal Fire to the appropriate county District Attorneys' offices are uncertain.

SEC Investigation

On March 20, 2019, PG&E Corporation learned that the SEC's San Francisco Regional Office is conducting an investigation related to PG&E Corporation's and the Utility's public disclosures and accounting for losses associated with the 2017 and 2018 Northern California wildfires and the 2015 Butte fire. PG&E Corporation and the Utility are unable to predict the timing and outcome of the investigation.

Clean-up and Repair Costs

The Utility incurred costs of $559 million for clean-up and repair of the Utility's facilities (including $204 million in capital expenditures) through March 31, 2019, in connection with the 2018 Camp fire. The Utility also incurred costs of $330 million for clean-up and repair of the Utility's facilities (including $157 million in capital expenditures) through March 31, 2019, in connection with the 2017 Northern California wildfires. The Utility is authorized to track and seek recovery of clean-up and repair costs through CEMA. (CEMA requests are subject to CPUC approval.) The Utility capitalizes and records as regulatory assets costs that are probable of recovery. At March 31, 2019, the CEMA balance related to the 2017 Northern California wildfires was $132 million, and is included in long-term regulatory assets on the Condensed Consolidated Balance Sheets. Additionally, the capital expenditures for clean-up and repair are included in property, plant and equipment at March 31, 2019.

Should PG&E Corporation and the Utility conclude that recovery of any clean-up and repair costs included in the CEMA is no longer probable, PG&E Corporation and the Utility will record a charge in the period such conclusion is reached. Failure to obtain a substantial or full recovery of these costs or any conclusion that such recovery is no longer probable, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Proposed Wildfire Assistance Fund

On May 1, 2019, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court seeking authorization to establish and fund a program (the "Wildfire Assistance Fund") to assist those displaced by the 2018 Camp fire and 2017 Northern California wildfires with the costs of temporary housing and other urgent needs. The Wildfire Assistance Fund is intended to aid certain wildfire claimants who are either uninsured or still in need of assistance for temporary housing expenses or other urgent needs. The Wildfire Assistance Fund would consist of $105 million deposited into a segregated account to be controlled by an independent third-party administrator, who will disburse and administer the funds. The administrator would be responsible for developing the specific eligibility requirements and application procedures for the distribution of the Wildfire Assistance Fund to eligible claimants. Up to $5 million of the Wildfire Assistance Fund could be used to pay administrative expenses. The filing of this motion is not an acknowledgement or admission by PG&E Corporation or the Utility of liability with respect of the 2018 Camp fire and 2017 Northern California wildfires. The motion is scheduled to be heard in the Bankruptcy Court on May 22, 2019. At March 31, 2019, the Utility's Condensed Consolidated Balance Sheet reflected liabilities of $14 billion related to third-party claims in connection with the 2018 Camp fire and 17 of the 2017 Northern California wildfires, which included amounts for temporary housing expenses.

2015 Butte Fire

In September 2015, a wildfire (the "2015 Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the 2015 Butte fire. According to Cal Fire's report, the 2015 Butte fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the 2015 Butte fire was caused when a gray pine tree contacted the Utility's electric line, which ignited portions of the tree and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

Third-Party Claims

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California, County of Sacramento. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council previously had authorized the coordination of all cases in Sacramento County. As of January 28, 2019, 95 known complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador. The complaints involve approximately 3,900 individual plaintiffs representing approximately 2,000 households and their insurance companies. These complaints are part of, or were in the process of being added to, the coordinated proceeding. Plaintiffs seek to recover damages and other costs, principally based on the doctrine of inverse condemnation and negligence theory of liability. Plaintiffs also seek punitive damages. Several plaintiffs dismissed the Utility's two vegetation management contractors from their complaints. The Utility does not expect the number of claimants to increase significantly in the future, because the statute of limitations for property damage and personal injury in connection with the 2015 Butte fire has expired. Further, due to the commencement of the Chapter 11 Cases, these plaintiffs have been stayed from continuing to prosecute pending litigation and from commencing new lawsuits against PG&E Corporation or the Utility on account of pre-petition obligations. On January 30, 2019, the Court in the coordinated proceeding issued an order staying the action.

On April 28, 2017, the Utility moved for summary adjudication on plaintiffs' claims for punitive damages. The court denied the Utility's motion and the Utility filed a writ with the Court of Appeal of the State of California, Third Appellate District. The writ was granted on July 2, 2018, directing the trial court to enter summary adjudication in favor of the Utility and to deny plaintiffs' claim for punitive damages under California Civil Code Section 3294. Plaintiffs sought rehearing and asked the California Supreme Court to review the Court of Appeal's decision. Both requests were denied. Neither the trial nor appellate courts originally addressed whether plaintiffs can seek punitive damages at trial under Public Utilities Code Section 2106. However, the trial court, in November 2018, denied a motion filed by the Utility that would have confirmed that punitive damages under Public Utilities Code Section 2106 are unavailable. The Utility believes a loss related to punitive damages is unlikely, but possible.

On June 22, 2017, the Superior Court of California, County of Sacramento ruled on a motion of several plaintiffs and found that the doctrine of inverse condemnation applies to the Utility with respect to the 2015 Butte fire. The court held, among other things, that the Utility had failed to put forth any evidence to support its contention that the CPUC would not allow the Utility to pass on its inverse condemnation liability through rate increases. While the ruling is binding only between the Utility and the plaintiffs in the coordination proceeding at the time of the ruling, others could make similar claims. On January 4, 2018, the Utility filed with the court a renewed motion for a legal determination of inverse condemnation liability, citing the November 30, 2017 CPUC decision denying the San Diego Gas & Electric Company application to recover wildfire costs in excess of insurance, and the CPUC declaration that it will not automatically allow utilities to spread inverse condemnation losses through rate increases.

On May 1, 2018, the Superior Court of California, County of Sacramento issued its ruling on the Utility's renewed motion in which the court affirmed, with minor changes, its tentative ruling dated April 25, 2018. The court determined that it is bound by earlier holdings of two appellate courts decisions, *Barham* and *Pacific Bell*. Further, the court stated that the Utility's constitutional arguments should be made to the appellate courts and suggested that, to the extent the Utility raises the public policy implications of the November 30, 2017 CPUC decision in the San Diego Gas & Electric Company cost recovery proceeding, these arguments should be addressed to the Legislature or CPUC. The Utility filed a writ with the Court of Appeal seeking immediate review of the court's decision. On June 18, 2018, after the writ was summarily denied, the Utility filed a Petition for Review with the California Supreme Court, which also was denied. On September 6, 2018, the court set a trial for some individual plaintiffs to begin on April 1, 2019. The Utility reached agreement with two plaintiffs in the litigation to stipulate to judgment against the Utility on inverse condemnation grounds. The court granted the Utility's stipulated judgment motion on November 29, 2018 and the Utility filed its appeal on December 11, 2018. As a result of the filing of the Chapter 11 Cases, these lawsuits, including the trial and the appeal from the stipulated judgment, are stayed.

In addition to the coordinated plaintiffs, Cal Fire, the OES, the County of Calaveras, and five smaller public entities (three fire districts, one water district and the California Department of Veterans Affairs) have brought suit or indicated that they intend to do so. The five smaller public entities filed their complaints in August 2018 and September 2018. They have been added to the coordinated proceedings. The Utility has settled the claims of the three fire protection districts.

On April 13, 2017, Cal Fire filed a complaint with the Superior Court of California, County of Calaveras, seeking to recover over $87 million for its costs incurred on the theory that the Utility and its vegetation management contractors were negligent, or violated the law, among other claims. On July 31, 2017, Cal Fire dismissed its complaint against Trees, Inc., one of the Utility's vegetation contractors. Cal Fire had requested that a trial of its claims be set in 2019, following any trial of the claims of the individual plaintiffs. On October 19, 2018, the Utility filed a motion for summary judgment arguing that Cal Fire cannot recover any fire suppression costs under the Third District Court of Appeal's decision in *Dep't of Forestry & Fire Prot. v. Howell (2017)* 18 Cal. App. 5th 154. The hearing on that motion was set for January 31, 2019, but the hearing and Cal Fire's case against the Utility are now stayed. Prior to the stay, the Utility and Cal Fire were also engaged in a mediation process.

Also, on February 20, 2018, the County of Calaveras filed suit against the Utility and the Utility's vegetation management contractors to recover damages and other costs, based on the doctrine of inverse condemnation and negligence theory of liability. The County also sought punitive damages. On March 2, 2018, the County served a mediation demand seeking in excess of $167 million, having previously indicated that it intended to bring an approximately $85 million claim against the Utility. This claim included costs that the County of Calaveras allegedly incurred or expected to incur for infrastructure damage, erosion control, and other costs. The Utility and the County of Calaveras settled the County's claims in November 2018 for $25.4 million.

Further, in May 2017, the OES indicated that it intended to bring a claim against the Utility that it estimated to be approximately $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the 2015 Butte fire. The Utility has not received any information or documentation from OES since its May 2017 statement. In June 2017, the Utility entered into an agreement with the OES that extends its deadline to file a claim to December 2020.

PG&E Corporation's and the Utility's obligations with respect to such outstanding claims are expected to be determined through the Chapter 11 process.

Estimated Losses from Third-Party Claims

In connection with the 2015 Butte fire, the Utility may be liable for property damages, business interruption, interest, and attorneys' fees without having been found negligent, through the doctrine of inverse condemnation.

In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility is found to have been negligent. While the Utility believes it was not negligent, there can be no assurance that a court would agree with the Utility.

The Utility's assessment of the estimated loss related to the 2015 Butte fire is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and certain other damages.

The Utility has determined that it is probable that it will incur a loss of $1.1 billion in connection with the 2015 Butte fire. While this amount includes the Utility's assumptions about fire suppression costs (including its assessment of the Cal Fire loss), it does not include any portion of the estimated claim from the OES. The Utility still does not have sufficient information to reasonably estimate any liability it may have for that additional claim.

The process for estimating costs associated with claims relating to the 2015 Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, management estimates and assumptions regarding the financial impact of the 2015 Butte fire may result in material increases to the loss accrued.

The following table presents changes in the third-party claims liability since December 31, 2015. The balance for the third-party claims liability is included in Wildfire-related claims in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets:

Loss Accrual (in millions)		
Balance at December 31, 2015	$	—
Accrued losses		750
Payments [(1)]		(60)
Balance at December 31, 2016		**690**
Accrued losses		350
Payments [(1)]		(479)
Balance at December 31, 2017		**561**
Accrued losses		—
Payments [(1)]		(335)
Balance at December 31, 2018		**226**
Accrued losses		**—**
Payments [(1)]		**(14)**
Balance as of March 31, 2019	**$**	**212**

[(1)] As of March 31, 2019, the Utility has paid $888 million of the $904 million in settlements to date in connection with the 2015 Butte fire.

If the Utility records losses in connection with claims relating to the 2015 Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected in the reporting periods during which additional charges are recorded.

Loss Recoveries

The Utility has liability insurance from various insurers, that provides coverage for third-party liability attributable to the 2015 Butte fire in an aggregate amount of $922 million. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. Through March 31, 2019, the Utility recorded $922 million for probable insurance recoveries in connection with losses related to the 2015 Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, the Utility has received $60 million in cumulative reimbursements from the insurance policies of its

vegetation management contractors (excluded from the table below). Recoveries of additional amounts under the insurance policies of the Utility's vegetation management contractors, including policies where the Utility is listed as an additional insured, are uncertain.

The following table presents changes in the insurance receivable since December 31, 2015. The balance for the insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets:

Insurance Receivable (in millions)		
Balance at December 31, 2015	$	—
Accrued insurance recoveries		625
Reimbursements		(50)
Balance at December 31, 2016		**575**
Accrued insurance recoveries		297
Reimbursements		(276)
Balance at December 31, 2017		**596**
Accrued insurance recoveries		—
Reimbursements		(511)
Balance at December 31, 2018		**85**
Accrued insurance recoveries		—
Reimbursements		(25)
Balance as of March 31, 2019	**$**	**60**

NOTE 11: OTHER CONTINGENCIES AND COMMITMENTS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. A provision for a loss contingency is recorded when it is both probable that a liability has been incurred and the amount of the liability can reasonably be estimated. PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses and record a charge that reflects their best estimate or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred.

The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows may be materially affected by the outcome of the following matters.

Enforcement and Litigation Matters

U.S. District Court Matters and Probation

On August 9, 2016, the jury in the federal criminal trial against the Utility in the United States District Court for the Northern District of California, in San Francisco, found the Utility guilty on one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act. On January 26, 2017, the court issued a judgment of conviction against the Utility. The court sentenced the Utility to a five-year corporate probation period, oversight by the Monitor for a period of five years, with the ability to apply for early termination after three years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service.

The probation includes a requirement that the Utility not commit any local, state, or federal crimes during the probation period. As part of the probation, the Utility has retained the Monitor at the Utility's expense. The goal of the Monitor is to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of its gas and electric operations, and to maintain effective ethics, compliance and safety related incentive programs on a Utility-wide basis.

On November 27, 2018, the court overseeing the Utility's probation issued an order requiring that the Utility, the United States Attorney's Office for the Northern District of California (the "USAO") and the Monitor provide written answers to a series of questions regarding the Utility's compliance with the terms of its probation, including what requirements of the Utility's probation "might be implicated were any wildfire started by reckless operation or maintenance of PG&E power lines" or "might be implicated by any inaccurate, slow, or failed reporting of information about any wildfire by PG&E." The court also ordered the Utility to provide "an accurate and complete statement of the role, if any, of PG&E in causing and reporting the recent 2018 Camp fire in Butte County and all other wildfires in California" since January 2017 ("Question 4 of the November 27 Order"). On December 5, 2018, the court issued an order requesting that the Office of the California Attorney General advise the court of its view on "the extent to which, if at all, the reckless operation or maintenance of PG&E power lines would constitute a crime under California law." The responses of the Attorney General were submitted on December 28, 2018, and the responses of the Utility, the USAO and the Monitor were submitted on December 31, 2018.

On January 3, 2019, the court issued a new order requiring that the Utility provide further information regarding the 2017 Atlas fire. The court noted that "[t]his order postpones the question of the adequacy of PG&E's response" to Question 4 of the November 27 Order. On January 4, 2019, the court issued another order requiring that the Utility provide, "with respect to each of the eighteen October 2017 Northern California wildfires that [Cal Fire] has attributed to [the Utility's] facilities," information regarding the wind conditions in the vicinity of each fire's origin and information about the equipment allegedly involved in each fire's ignition. The responses of the Utility were submitted on January 10, 2019.

On January 9, 2019, the court ordered the Utility to appear in court on January 30, 2019, as a result of the court's finding that "there is probable cause to believe there has been a violation of the conditions of supervision" with respect to reporting requirements related to the 2017 Honey fire. In addition, on January 9, 2019, the court issued an order (the "January 9 Order") proposing to add new conditions of probation that would require the Utility, among other things, to:

- prior to June 21, 2019, "re-inspect all of its electrical grid and remove or trim all trees that could fall onto its power lines, poles or equipment in high-wind conditions, . . . identify and fix all conductors that might swing together and arc due to slack and/or other circumstances under high-wind conditions[,] identify and fix damaged or weakened poles, transformers, fuses and other connectors [and] identify and fix any other condition anywhere in its grid similar to any condition that contributed to any previous wildfires,"

- "document the foregoing inspections and the work done and . . . rate each segment's safety under various wind conditions" and

- at all times from and after June 21, 2019, "supply electricity only through those parts of its electrical grid it has determined to be safe under the wind conditions then prevailing."

The Utility was ordered to show cause by January 23, 2019 as to why the Utility's conditions of probation should not be modified as proposed. The Utility's response was submitted on January 23, 2019. The court requested that Cal Fire file a public statement, and invited the CPUC to comment, by January 25, 2019. On January 30, 2019, the court found that the Utility had violated a condition of its probation with respect to reporting requirements related to the 2017 Honey fire. Also, on January 30, 2019, the court ordered the Utility to submit to the court on February 6, 2019 the 2019 Wildfire Safety Plan that the Utility was required to submit to the CPUC by February 6, 2019 in accordance with SB 901, and invited interested parties to comment on such plan by February 20, 2019. In addition, on February 14, 2019, the court ordered the Utility to provide additional information, including on its vegetation clearance requirements. The Utility submitted its response to the court on February 22, 2019. As of April 30, 2019, to the Utility's knowledge, no parties have submitted comments to the court on the 2019 Wildfire Safety Plan.

On March 5, 2019, the court issued an order proposing to add new conditions of probation that would require the Utility, among other things, to:

- "fully comply with all applicable laws concerning vegetation management and clearance requirements;"

- "fully comply with the specific targets and metrics set forth in its wildfire mitigation plan, including with respect to enhanced vegetation management;"

- submit to "regular, unannounced inspections" by the Monitor "of PG&E's vegetation management efforts and equipment inspection, enhancement, and repair efforts" in connection with a requirement that the Monitor "assess PG&E's wildfire mitigation and wildfire safety work;"

- “maintain traceable, verifiable, accurate, and complete records of its vegetation management efforts” and report to the Monitor monthly on its vegetation management status and progress; and

- “ensure that sufficient resources, financial and personnel, including contractors and employees, are allocated to achieve the foregoing” and to forgo issuing “any dividends until [the Utility] is in compliance with all applicable vegetation management requirements as set forth above.”

The court ordered all parties to show cause by March 22, 2019, as to why the Utility’s conditions of probation should not be modified as proposed. The responses of the Utility, the USAO, Cal Fire, the CPUC, and non-party victims were filed on March 22, 2019. At a hearing on April 2, 2019, the court indicated it would impose the new conditions of probation proposed on March 5, 2019, on the Utility, and on April 3, 2019, the court issued an order imposing the new terms though amended the second condition to clarify that “[f]or purposes of this condition, the operative wildfire mitigation plan will be the plan ultimately approved by the CPUC.” Also, on April 2, 2019, the court directed the parties to submit briefing by April 16, 2019, regarding whether the court can extend the term of probation beyond five years in light of the violation that has been adjudicated and whether the Monitor reports should be made public. The responses of the Utility, the USAO, and the Monitor were filed on April 16, 2019. The Utility’s response contended that the term of probation may not be extended beyond five years and the USAO’s response contended that whether the term of probation could be extended beyond five years was an open legal issue. A sentencing hearing currently is scheduled for May 7, 2019. PG&E Corporation and the Utility are unable to predict the outcome of this proceeding.

CPUC and FERC Matters

Order Instituting an Investigation and Order to Show Cause into the Utility’s Locate and Mark practices

On December 14, 2018, the CPUC issued an OII and order to show cause (the “OII”) to assess the Utility’s practices and procedures related to the locating and marking of natural gas facilities. The OII directs the Utility to show cause as to why the CPUC should not find violations in this matter, and why the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. The Utility also is directed in the OII to provide a report on specific matters, including that it is conducting locate and mark programs in a safe manner.

The OII cites a report by the SED dated December 6, 2018, which alleges that the Utility violated the law pertaining to the locating and marking of its gas facilities and falsified records related to its locate and mark activities between 2012 and 2017. As described in the OII, the SED cites reports issued in this matter by two consultants retained by the Utility, that (i) included certain facts and conclusions about the extent of inaccuracies in the Utility’s late tickets and the reasons for the inaccuracies, and (ii) provided an analysis, based on the available data, of tickets that should be properly categorized as late, and identification of associated dig-ins. As a result, the OII will determine whether the Utility violated any provision of the Public Utilities Code, general orders, federal law adopted by California, other rules, or requirements, and/or other state or federal law, by its locate and mark policies, practices, and related issues, and the extent to which the Utility’s practices with regard to locate and mark may have diminished system safety.

The CPUC indicates that it has not concluded that the Utility has violated the law in any instance pertaining to late tickets, locating and marking, or any matter related to either, or to any other matter raised in this OII. However, if violations are found, the CPUC will consider what monetary fines and other remedies are appropriate, will review the duration of violations and, if supported by the evidence, it will consider ordering daily fines.

On March 14, 2019, as directed by the CPUC, the Utility submitted a report that addressed the SED report and responded to the order to show cause. A prehearing conference was held on April 4, 2019, to establish scope and a procedural schedule. The Assigned Commissioner and ALJ have not yet issued a Scoping Memo for the proceeding. An initial settlement conference at the CPUC currently is scheduled for May 2, 2019.

Based on the information currently available, PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties, including fines or other remedies, on the Utility. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC’s wide discretion and the number of factors that can be considered in determining penalties. The Utility is unable to predict the timing and outcome of this proceeding.

This proceeding is not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases; however, collection efforts in connection with fines or penalties arising out of such proceedings are stayed.

Order Instituting an Investigation into Compliance with Ex Parte Communication Rules

On April 26, 2018, the CPUC approved the revised proposed decision issued on April 3, 2018, adopting the settlement agreement jointly submitted to the CPUC on March 28, 2017, as modified (the "settlement agreement") by the Utility, the Cities of San Bruno and San Carlos, Cal PA (formerly known as the Office of Ratepayer Advocates or ORA), the SED, and TURN.

The decision results in a total penalty of $97.5 million comprised of: (1) a $12 million payment to the California General Fund, (2) forgoing collection of $63.5 million of GT&S revenue requirements for the years 2018 ($31.75 million) and 2019 ($31.75 million), (3) a $10 million one-time revenue requirement adjustment to be amortized in equivalent annual amounts over the Utility's next GRC cycle (i.e., the 2020 GRC), and (4) compensation payments to the Cities of San Bruno and San Carlos in a total amount of $12 million ($6 million to each city). In addition, the settlement agreement provides for certain non-financial remedies, including enhanced noticing obligations between the Utility and CPUC decision-makers, as well as certification of employee training on the CPUC ex parte communication rules. Under the terms of the settlement agreement, customers will bear no costs associated with the financial remedies set forth above.

As a result of the CPUC's April 26, 2018 decision, on May 17, 2018, the Utility made a $12 million payment to the California General Fund and $6 million payments to each of the Cities of San Bruno and San Carlos. At March 31, 2019, PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets include an $8 million accrual for a portion of the 2019 GT&S revenue requirement reduction. In accordance with accounting rules, adjustments related to revenue requirements are recorded in the periods in which they are incurred.

The CPUC also ordered a second phase in this proceeding to determine if any of the additional communications that the Utility reported to the CPUC on September 21, 2017, violate the CPUC ex parte rules. On March 15, 2019, the ALJ held a prehearing conference. On April 18, 2019, the Assigned Commissioner issued a Scoping Memo and Ruling setting the schedule for the second phase. In accordance with that schedule, on April 26, 2019, the parties filed a joint report stating that the parties were close to reaching agreement on a joint evidentiary record and thus it is unnecessary for the CPUC to schedule evidentiary hearings. The parties expect to submit the joint evidentiary record by May 15, 2019, with briefing to follow in June and July 2019. The Utility is unable to predict the timing and outcome of the second phase in this proceeding.

For more information about the proceeding, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.

Transmission Owner Rate Case Revenue Subject to Refund

The FERC determines the amount of authorized revenue requirements, including the rate of return on electric transmission assets, that the Utility may collect in rates in the TO rate case. The FERC typically authorizes the Utility to charge new rates based on the requested revenue requirement, subject to refund, before the FERC has issued a final decision. The Utility bills and records revenue based on the amounts requested in its rate case filing and records a reserve for its estimate of the amounts that are probable of refund. Rates subject to refund went into effect on March 1, 2017, and March 1, 2018, for TO18 and TO19, respectively. Rates subject to refund for TO20 will go into effect on May 1, 2019.

On October 1, 2018, the ALJ issued an initial decision in the TO18 rate case and the Utility filed initial briefs on October 31, 2018, in response to the ALJ's recommendations. The Utility expects the FERC to issue a decision in the TO18 rate case by mid-2019, however, that decision will likely be the subject of requests for rehearing and appeal. The Utility is unable to predict the timing of when a final decision will be issued. On September 21, 2018, the Utility filed an all-party settlement with FERC in connection with TO19. As part of the settlement, the TO19 revenue requirement will be set at 98.85% of the revenue requirement for TO18 that will be determined in the TO18 final decision. The Utility is unable to predict the timing or outcome of FERC's decisions in these proceedings.

Natural Gas Transmission Pipeline Rights-of-Way

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to address a self-reported violation whereby the Utility did not properly identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey had been completed and that remediation work, including removal of the encroachments, was expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility in the future based on the Utility's failure to continuously survey its system and remove encroachments. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the SED's wide discretion and the number of factors that can be considered in determining penalties.

Other Matters

PG&E Corporation and the Utility are subject to various claims, lawsuits, and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters") totaled $98 million at December 31, 2018. These amounts were included in Other current liabilities in the Condensed Consolidated Balance Sheets. On the Petition Date, these amounts were moved to LSTC. PG&E Corporation and the Utility do not believe it is reasonably possible that the resolution of these matters will have a material impact on their financial condition, results of operations, or cash flows.

2015 GT&S Rate Case Capital Disallowance

On June 23, 2016, the CPUC approved a final phase one decision in the Utility's 2015 GT&S rate case. The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted in the prior GT&S rate case. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. Additional charges may be required in the future based on the outcome of the CPUC's audit of 2011 through 2014 capital spending. Capital disallowances are reflected in operating and maintenance expenses in the Condensed Consolidated Statements of Income. For more information, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.

Environmental Remediation Contingencies

The Utility's environmental remediation liability is primarily included in non-current liabilities on the Condensed Consolidated Balance Sheets and is comprised of the following:

	Balance at	
(in millions)	**March 31, 2019**	**December 31, 2018**
Topock natural gas compressor station	$ 358	$ 369
Hinkley natural gas compressor station	145	146
Former manufactured gas plant sites owned by the Utility or third parties (1)	525	520
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites (2)	107	111
Fossil fuel-fired generation facilities and sites (3)	131	137
Total environmental remediation liability	**$ 1,266**	**$ 1,283**

(1) Primarily driven by the following sites: Vallejo, San Francisco East Harbor, Napa, Beach Street, and San Francisco North Beach.
(2) Primarily driven by the Geothermal landfill and Shell Pond site.
(3) Primarily driven by the San Francisco Potrero Power Plant.

The Utility's gas compressor stations, former manufactured gas plant sites, power plant sites, gas gathering sites, and sites used by the Utility for the storage, recycling, and disposal of potentially hazardous substances are subject to requirements issued by the Environmental Protection Agency under the Federal Resource Conservation and Recovery Act in addition to other state hazardous waste laws. The Utility has a comprehensive program in place designed to comply with federal, state, and local laws and regulations related to hazardous materials, waste, remediation activities, and other environmental requirements. The Utility assesses and monitors the environmental requirements on an ongoing basis, and implements changes to its program as deemed appropriate. The Utility's remediation activities are overseen by the DTSC, several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility's environmental remediation liability at March 31, 2019, reflects its best estimate of probable future costs for remediation based on the current assessment data and regulatory obligations. Future costs will depend on many factors, including the extent of work necessary to implement final remediation plans and the Utility's time frame for remediation. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations, financial condition, and cash flows during the period in which they are recorded. At March 31, 2019, the Utility expected to recover $920 million of its environmental remediation liability for certain sites through various ratemaking mechanisms authorized by the CPUC.

For more information, see remediation site descriptions below and see Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.

Natural Gas Compressor Station Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California DTSC and the U.S. Department of the Interior. On April 24, 2018, the DTSC authorized the Utility to build an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. Construction activities began in October 2018 and will continue for several years. The Utility's undiscounted future costs associated with the Topock site may increase by as much as $303 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Topock site are expected to be recovered primarily through the HSM, where 90% of the costs are recovered in rates.

Hinkley Site

The Utility has been implementing remediation measures at the Hinkley site to reduce the mass of the chromium plume in groundwater and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a clean-up and abatement order directing the Utility to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order sets plume capture requirements, requires a monitoring and reporting program, and includes deadlines for the Utility to meet interim cleanup targets. The United States Geological Survey team is currently conducting a background study on the site to better define the chromium plume boundaries. The background study is expected to be finalized in 2019. The Utility's undiscounted future costs associated with the Hinkley site may increase by as much as $142 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

Former Manufactured Gas Plants

Former MGPs used coal and oil to produce gas for use by the Utility's customers before natural gas became available. The by-products and residues of this process were often disposed of at the MGPs themselves. The Utility has undertaken a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. The Utility's undiscounted future costs associated with MGP sites may increase by as much as $514 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the MGP sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Utility-Owned Generation Facilities and Third-Party Disposal Sites

Utility-owned generation facilities and third-party disposal sites often involve long-term remediation. The Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as $132 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the Utility-owned generation facilities and third-party disposal sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Fossil Fuel-Fired Generation Sites

In 1998, the Utility divested its generation power plant business as part of generation deregulation. Although the Utility sold its fossil-fueled power plants, the Utility retained the environmental remediation liability associated with each site. The Utility's undiscounted future costs associated with fossil fuel-fired generation sites may increase by as much as $91 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the fossil fuel-fired sites will not be recovered through rates.

Insurance

Wildfire Insurance

In 2018, PG&E Corporation and the Utility renewed their liability insurance coverage for wildfire events in an aggregate amount of approximately $1.4 billion for the period from August 1, 2018 through July 31, 2019, comprised of $700 million for general liability (subject to an initial self-insured retention of $10 million per occurrence), and $700 million for property damages only, which property damage coverage includes an aggregate amount of approximately $200 million through the reinsurance market where a catastrophe bond was utilized. Various coverage limitations applicable to different insurance layers could result in substantial uninsured costs in the future depending on the amount and type of damages.

PG&E Corporation's and the Utility's cost of obtaining wildfire insurance coverage has increased to $360 million, compared to the adopted approximately $50 million that the Utility is currently recovering through rates through December 31, 2019. The Utility intends to seek recovery for the full amount of premium costs paid in excess of the amount the Utility currently is recovering from customers through the end of the current GRC period, which ends on December 31, 2019.

PG&E Corporation and the Utility record a receivable for insurance recoveries when it is deemed probable that recovery of a recorded loss will occur. Through March 31, 2019, PG&E Corporation and the Utility recorded $1.38 billion for probable insurance recoveries in connection with the 2018 Camp fire and $842 million for probable insurance recoveries in connection with the 2017 Northern California wildfires. These amounts reflect an assumption that the cause of each fire is deemed to be a separate occurrence under the insurance policies. The amount of the receivable is subject to change based on additional information. PG&E Corporation and the Utility intend to seek full recovery for all insured losses and believe it is reasonably possible that they will record a receivable for the full amount of the insurance limits in the future.

Nuclear Insurance

The Utility maintains multiple insurance policies through NEIL and European Mutual Association for Nuclear Insurance, covering nuclear or non-nuclear events at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of the policy renewal on April 1, 2019, the maximum aggregate annual retrospective premium obligation for the Utility would be approximately $44 million. If European Mutual Association for Nuclear Insurance losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $4 million, as of the policy renewal on April 1, 2019. For more information about the Utility's nuclear insurance coverage, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.

Tax Matters

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of audits. As of March 31, 2019, it is reasonably possible that unrecognized tax benefits will decrease by approximately $10 million within the next 12 months. PG&E Corporation and the Utility believe that the majority of the decrease will not impact net income.

PG&E Corporation does not believe that the Chapter 11 Cases resulted in loss of or limitation on the utilization of any of the tax carryforwards. PG&E Corporation will continue to monitor the status of tax carryforwards during the pendency of the Chapter 11 Cases.

Purchase Commitments

In the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity; natural gas supply, transportation, and storage; nuclear fuel supply and services; and various other commitments. At December 31, 2018, the Utility had undiscounted future expected obligations of approximately $40 billion. (See Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.) The Utility has not entered into any new material commitments during the three months ended March 31, 2019.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers.

The Utility is regulated primarily by the CPUC and the FERC. The CPUC has jurisdiction over the rates, terms, and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility is also subject to the jurisdiction of other federal, state, and local governmental agencies.

This is a combined quarterly report of PG&E Corporation and the Utility and should be read in conjunction with each company's separate Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in this quarterly report. It also should be read in conjunction with the 2018 Form 10-K.

Chapter 11 Proceedings

On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. PG&E Corporation's and the Utility's Chapter 11 Cases are being jointly administered under the caption In re: PG&E Corporation and Pacific Gas and Electric Company, Case No. 19-30088 (DM). For additional information regarding the Chapter 11 Cases, refer to the website maintained by Prime Clerk, LLC, PG&E Corporation's and the Utility's claims and noticing agent, at http://restructuring.primeclerk.com/pge.

For more information about the Chapter 11 Cases, see "Item 1A. Risk Factors-Risks Related to Chapter 11 Proceedings and Liquidity" and "Item 7. MD&A-Chapter 11 Proceedings" in the 2018 Form 10-K and Notes 2 and 5 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of this Form 10-Q.

Going Concern

The accompanying Condensed Consolidated Financial Statements to this Form 10-Q have been prepared on a going concern basis, which contemplates the continuity of operations, the realization of assets and the satisfaction of liabilities in the normal course of business. However, PG&E Corporation and the Utility are facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in Northern California in 2017 and 2018. As a result of these challenges, such realization of assets and satisfaction of liabilities are subject to uncertainty. For more information about the 2018 Camp fire and 2017 Northern California wildfires, see Note 10 of the Notes to the Condensed Consolidated Financial Statements and the 2018 Form 10-K.

Management has concluded that uncertainty regarding these matters raises substantial doubt about PG&E Corporation's and the Utility's ability to continue as going concerns, and their independent registered public accountants included an explanatory paragraph in their auditors' reports relating to the consolidated balance sheets of PG&E Corporation and the Utility as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2018, included in the 2018 Form 10-K, which stated certain conditions exist which raise substantial doubt about PG&E Corporation's and the Utility's ability to continue as going concerns in relation to the foregoing. The Condensed Consolidated Financial Statements do not include any adjustments that might result from the outcome of these uncertainties. For more information about these matters, see Notes 1 and 2 to the Condensed Consolidated Financial Statements and the 2018 Form 10-K.

Summary of Changes in Net Income and Earnings per Share

PG&E Corporation's net income available for common shareholders was $136 million in the three months ended March 31, 2019, compared to net income available for common shareholders of $442 million in the same period in 2018. In the three months ended March 31, 2019, PG&E Corporation recognized increased charges related to enhanced and accelerated inspections of transmission and distribution assets, clean up and repair costs relating to the 2018 Camp fire, and costs associated with PG&E Corporation's and the Utility's Chapter 11 filings, compared to the same period in 2018.

Key Factors Affecting Financial Results

PG&E Corporation and the Utility believe that their financial condition, results of operations, liquidity, and cash flows may be materially affected by the following factors:

- *The Outcome of the Chapter 11 Cases.* For the duration of the Chapter 11 Cases, PG&E Corporation's and the Utility's business is subject to the risks and uncertainties of bankruptcy. For example, the Chapter 11 Cases could adversely affect the Utility's relationships with suppliers and employees which, in turn, could adversely affect the value of the business and assets of PG&E Corporation and the Utility. PG&E Corporation and the Utility also expect to incur increased legal and other professional costs associated with the Chapter 11 Cases and the reorganization. At this time, it is not possible to predict with certainty the effect of the Chapter 11 Cases on their business or various creditors, or whether or when PG&E Corporation and the Utility will emerge from bankruptcy. PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity and cash flows depend upon confirming, and successfully implementing, on a timely basis, a plan of reorganization.

- *The Utility's Ability to Fund Ongoing Operations and Other Capital Needs.* In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement, which was approved on a final basis on March 27, 2019. For the duration of the Chapter 11 Cases, PG&E Corporation and the Utility expect that the DIP Credit Agreement, together with cash on hand, cash flow from operations and distributions received from subsidiaries, will be the Utility's primary source of capital to fund ongoing operations and other capital needs and that they will have limited, if any, access to additional financing. In the event that cash on hand, cash flow from operations, distributions received from subsidiaries, and availability under the DIP Credit Agreement are not sufficient to meet these liquidity needs, PG&E Corporation and the Utility may be required to seek additional financing, and can provide no assurance that additional financing would be available or, if available, offered on acceptable terms. The amount of any such additional financing could be limited by negative covenants in the DIP Credit Agreement, which include restrictions on PG&E Corporation's and the Utility's ability to, among other things, incur additional indebtedness and create liens on assets.

- *The Impact of Wildfires.* PG&E Corporation and the Utility face several uncertainties in connection with the 2018 Camp fire and 2017 Northern California wildfires, related to:

  - the amount of possible loss related to third-party claims (as of March 31, 2019, the Utility recorded total charges of $14 billion, which reflects the low end of the range of reasonably estimated losses and is subject to change based on additional information), which aggregate possible losses, if the Utility were found liable for certain or all of the costs, expenses and other losses in connection with the 2018 Camp fire and 2017 Northern California wildfires (other than potential punitive damages, fines and penalties or damages related to future claims), could exceed $30 billion; and punitive damages, which could be material;

  - the impact of investigations, including criminal and SEC investigations;

  - fines or penalties, which could be material, if the CPUC or any law enforcement agency were to bring an enforcement action, including a criminal proceeding, and determined that the Utility had failed to comply with applicable laws and regulations;

  - the amount of damages in respect of future claims, which could be material;

  - the applicability of the doctrine of inverse condemnation in the 2018 Camp fire and 2017 Northern California wildfires litigation, which the Utility intends to continue to challenge during the pendency of its Chapter 11 Case; the applicability of other theories of liability, including negligence, related to the 2018 Camp fire and 2017 Northern California wildfire claims;

  - the recoverability of the above mentioned costs, even if a court decision imposes liability under the doctrine of inverse condemnation;

  - the amount of the Customer Harm Threshold under SB 901 and the timing of any recovery by the Utility in excess of the Customer Harm Threshold in a proceeding before the CPUC;

  - the impact of the Strike Force Report;

  - the amount and recoverability of enhanced and accelerated inspection costs of the Utility’s electric transmission and distribution assets (the Utility incurred costs of $210 million for enhanced and accelerated inspection and repair costs for the three months ended March 31, 2019); and

  - the amount and recoverability of clean-up and repair costs (the Utility incurred costs of $889 million for clean-up and repair of the Utility’s facilities through March 31, 2019).

  (See Notes 4 and 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and Item 1A. Risk Factors in Part II.)

- *The Outcome of Other Enforcement, Litigation, and Regulatory Matters*. The Utility’s financial results may continue to be impacted by the outcome of other current and future enforcement, litigation (to the extent not stayed as a result of the Chapter 11 Cases), and regulatory matters, including the outcome of the Locate and Mark OII, phase two of the Safety Culture OII, the outcome of phase two of the ex parte OII, the sentencing terms of the Utility’s January 27, 2017 federal criminal conviction, including the oversight of the Utility’s probation and the potential recommendations by the Monitor, and potential penalties in connection with the Utility’s safety and other self-reports. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- *The Timing and Outcome of Ratemaking Proceedings*. The Utility’s financial results may be impacted by the timing and outcome of its 2019 GT&S rate case, 2020 GRC, FERC TO18, TO19, and TO20 rate cases, 2020 cost of capital proceeding, and its ability to timely recover costs not currently in rates, including costs already incurred and future costs tracked in its CEMA, WEMA, FHPMA, and Fire Risk Mitigation Memorandum Account (FRMMA) that are incurred in connection with the Utility's 2019 Wildfire Safety Plan, the amount of which is substantial and is expected to increase. The outcome of regulatory proceedings can be affected by many factors, including intervening parties’ testimonies, potential rate impacts, the Utility’s reputation, the regulatory and political environments, and other factors. (See Notes 4 and 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and “Regulatory Matters” below.)

- *The Utility's Compliance with the CPUC Capital Structure*. The CPUC's capital structure decisions require the Utility to maintain a 52% equity ratio on average over the period that the authorized capital structure is in place, and to file an application for a waiver to the capital structure condition if an adverse financial event reduces its equity ratio by 1% or more. Due to the net charges recorded in connection with the 2018 Camp fire and the 2017 Northern California wildfires as of December 31, 2018, the Utility submitted to the CPUC an application for a waiver of the capital structure condition on February 28, 2019. The waiver is subject to CPUC approval. The CPUC's decisions state that the Utility shall not be considered in violation of these conditions during the period the waiver application is pending resolution. The Utility is unable to predict the timing and outcome of its waiver application. (See "Regulatory Matters" below.)

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, or that could cause future results to differ from historical results, see "Item 1A. Risk Factors" in this Form 10-Q and the 2018 Form 10-K. In addition, this quarterly report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

RESULTS OF OPERATIONS

PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income (loss) available for common shareholders for the three months ended March 31, 2019 and 2018:

	Three Months Ended March 31,	
(in millions)	**2019**	**2018**
Consolidated Total	$ 136	$ 442
PG&E Corporation	3	(7)
Utility	$ 133	$ 449

PG&E Corporation's net income (loss) primarily consists of income taxes and interest expense on long-term debt.

Utility

The table below shows certain items from the Utility's Condensed Consolidated Statements of Income for the three months ended March 31, 2019 and 2018. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs), and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

	Three Months Ended March 31, 2019			Three Months Ended March 31, 2018		
	Revenues/Costs:			Revenues/Costs:		
(in millions)	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$ 1,913	$ 879	$ 2,792	$ 1,937	$ 1,014	$ 2,951
Natural gas operating revenues	794	425	1,219	738	367	1,105
Total operating revenues	**2,707**	**1,304**	**4,011**	**2,675**	**1,381**	**4,056**
Cost of electricity	—	599	599	—	819	819
Cost of natural gas	—	339	339	—	289	289
Operating and maintenance	1,694	410	2,104	1,251	353	1,604
Wildfire-related claims, net of insurance recoveries	—	—	—	(7)	—	(7)
Depreciation, amortization, and decommissioning	797	—	797	752	—	752
Total operating expenses	**2,491**	**1,348**	**3,839**	**1,996**	**1,461**	**3,457**
Operating income (loss)	**216**	**(44)**	**172**	**679**	**(80)**	**599**
Interest income	21	—	21	9	—	9
Interest expense	(101)	—	(101)	(217)	—	(217)
Other income, net	22	44	66	29	80	109
Reorganization items	(111)	—	(111)	—	—	—
Income before income taxes	$ 47	$ —	$ 47	$ 500	$ —	$ 500
Income tax provision [(1)]			(86)			48
Net income			133			452
Preferred stock dividend requirement [(1)]			—			3
Income Available for Common Stock			**$ 133**			**$ 449**

[(1)] These items impacted earnings for the three months ended March 31, 2019 and 2018.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for the three months ended March 31, 2019 and 2018, focusing on revenues and expenses that impacted earnings for these periods.

Operating Revenues

The Utility's electric and natural gas operating revenues that impacted earnings increased by $32 million, or 1%, in the three months ended March 31, 2019, compared to the same period in 2018, primarily due to increased base revenues authorized in the 2017 GRC, partially offset by tax benefits resulting from the Tax Act expected to be returned to customers.

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased by $443 million, or 35%, in the three months ended March 31, 2019, compared to the same period in 2018, primarily due to $210 million related to enhanced and accelerated inspections and repairs of transmission and distribution assets and $179 million for clean-up and repair costs relating to the 2018 Camp fire, with no similar charges in the same period in 2018. Additionally, the Utility incurred costs of $26 million in additional legal and other costs relating to the 2017 Northern California wildfires and the 2018 Camp fire (the Utility recorded $34 million for legal and other costs relating to the 2017 Northern California wildfires and $13 million relating to the 2018 Camp fire in the three months ended March 31, 2019, as compared to $21 million relating to the 2017 Northern California wildfires in the same period in 2018).

Wildfire-related claims, net of insurance recoveries

Costs related to wildfires that impacted earnings increased by $7 million in the three months ended March 31, 2019, compared to the same period in 2018. In 2018, the Utility recognized a $7 million insurance recovery from a third-party contractor related to the Butte fire, with no corresponding recoveries in 2019.

(See "Item 1A. Risk Factors" in the 2018 Form 10-K and Note 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of this Form 10-Q.)

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses that impacted earnings increased by $45 million, or 6%, in the three months ended March 31, 2019, compared to the same period in 2018, primarily due to capital additions.

Interest Income

There was no material change to interest income that impacted earnings for the periods presented.

Interest Expense

Interest expense that impacted earnings decreased by $116 million, or 53%, in the three months ended March 31, 2019, compared to the same period in 2018, primarily due to the cessation of interest accruals on outstanding pre-petition debt beginning January 29, 2019 in connection with the Chapter 11 Cases.

Other Income, Net

There were no material changes to other income, net, that impacted earnings for the periods presented.

Reorganization items, net

Reorganization items, net increased by $111 million in the three months ended March 31, 2019, compared to the same period in 2018, due to $120 million of expenses directly associated with the Utility's Chapter 11 filing in the three months ended March 31, 2019, partially offset by interest income of $9 million, with no similar charges in the same period in 2018.

(See "Item 1A. Risk Factors" in the 2018 Form 10-K and Note 2 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of this Form 10-Q.)

Income Tax Provision

The income tax provision decreased by $134 million in the three months ended March 31, 2019, as compared to the same period in 2018. The decrease in the income tax provision and effective tax rate were primarily the result of lower pretax income in the three months ended March 31, 2019, compared to the same period in 2018.

The following table reconciles the income tax expense at the federal statutory rate to the income tax provision:

	Three Months Ended March 31,	
	2019	2018
Federal statutory income tax rate	21.0 %	21.0 %
Increase (decrease) in income tax rate resulting from:		
State income tax (net of federal benefit) [(1)]	(17.7)%	2.3 %
Effect of regulatory treatment of fixed asset differences [(2)]	(179.2)%	(16.5)%
Tax credits	(5.8)%	(0.6)%
Other, net	(0.6)%	3.4 %
Effective tax rate	**(182.3)%**	**9.6 %**

[(1)] Includes the effect of state flow-through ratemaking treatment.

[(2)] Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by various CPUC decisions. All amounts are impacted by the level of income before income taxes. The various CPUC rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. In 2018 and 2019, the amounts also reflect the impact of the amortization of excess deferred tax benefits to be refunded to customers as a result of the Tax Act passed in December 2017.

Utility Revenues and Costs that did not Impact Earnings

Fluctuations in revenues that did not impact earnings are primarily driven by electricity and natural gas procurement costs. See below for more information.

Cost of Electricity

The Utility's cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. The costs also include net sales (Utility owned generation and third parties) in the CAISO electricity markets. (See Note 8 of the Notes to the Condensed Consolidated Financial Statements in Item 1.) The Utility's total purchased power is driven by customer demand, net CAISO electricity market sales, the availability of the Utility's own generation facilities (including Diablo Canyon and its hydroelectric plants), and the cost-effectiveness of each source of electricity.

	Three Months Ended March 31,	
(in millions)	2019	2018
Cost of purchased power, net [(1)]	$ 499	$ 753
Fuel used in generation facilities	100	66
Total cost of electricity	**$ 599**	**$ 819**
Average cost of purchased power per kWh [(2)]	$ 0.346	$ 0.123
Total purchased power, net (in millions of kWh)	**1,443**	**6,110**

[(1)] Cost of purchased power, net decreased for the three months ended March 31, 2019, compared to the same period in 2018, primarily due to lower Utility electric customer demand, driven by customer departures to CCAs and DA providers, and by higher net sales in the CAISO electricity markets.

[(2)] Average cost of purchased power increased for the three months ended March 31, 2019, compared to the same period in 2018, reflecting the differences between contracted power purchases, net sales in the CAISO electricity markets, and increased customer departures.

Cost of Natural Gas

The Utility's cost of natural gas includes the costs of procurement, storage and transportation of natural gas, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 8 of the Notes to the Condensed Consolidated Financial Statements in Item 1.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand.

	Three Months Ended March 31,	
(in millions)	**2019**	**2018**
Cost of natural gas sold	$ 309	$ 257
Transportation cost of natural gas sold	30	32
Total cost of natural gas	**$ 339**	**$ 289**
Average cost per Mcf [(1)] of natural gas sold	$ 3.29	$ 3.03
Total natural gas sold (in millions of Mcf)	**94**	**85**

(1) One thousand cubic feet

Operating and Maintenance Expenses

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings.

Other Income, Net

The Utility's other income, net that did not impact earnings includes pension and other post-retirement benefit costs that fluctuate primarily from market and interest rate changes.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement. The DIP Credit Agreement provides for $5.5 billion in senior secured superpriority debtor in possession credit facilities in the form of (i) a revolving credit facility in an aggregate amount of $3.5 billion (the "DIP Revolving Facility"), including a $1.5 billion letter of credit subfacility, (ii) a term loan facility in an aggregate principal amount of $1.5 billion (the "DIP Initial Term Loan Facility") and (iii) a delayed draw term loan facility in an aggregate principal amount of $500 million (the "DIP Delayed Draw Term Loan Facility", together with the DIP Revolving Facility and the DIP Initial Term Loan Facility, the "DIP Facilities"), subject to the terms and conditions set forth therein. On March 27, 2019, the Bankruptcy Court approved the DIP Facilities on a final basis, authorizing the Utility to borrow up to the full amount of the DIP Revolving Facility (including the full amount of the $1.5 billion letter of credit subfacility), the DIP Initial Term Loan Facility and the DIP Delayed Draw Term Loan Facility, in each case subject to the terms and conditions of the DIP Credit Agreement. (For more information on the DIP Credit Agreement, see "DIP Credit Agreement" below and Note 5 of the Notes to the Consolidated Financial Statements in Item 1.)

For the duration of the Chapter 11 Cases, the Utility's ability to fund operations, finance capital expenditures and pay other ongoing expenses and make distributions to PG&E Corporation will primarily depend on the levels of its operating cash flows and availability under the DIP Credit Agreement. The Utility expects that the DIP Facilities will provide it with sufficient liquidity to fund its ongoing operations, including its ability to provide safe service to customers, during the Chapter 11 Cases. For the duration of the Chapter 11 Cases, PG&E Corporation's ability to fund operations and pay other ongoing expenses will primarily depend on cash on hand and intercompany transfers. In the event that PG&E Corporation's and the Utility's capital needs increase materially due to unexpected events or transactions, additional financing outside of the DIP Facilities may be required, which would be subject to approval by the Bankruptcy Court. Such approval is not assured. For more information on PG&E Corporation's and the Utility's material commitments for capital expenditures, see "Regulatory Matters" below.

During 2018 and January 2019, PG&E Corporation's and the Utility's credit ratings were subject to multiple downgrades by Fitch, S&P and Moody's including to ratings below investment grade and ultimately to "D" or low "C" ratings. As of March 31, 2019, Moody's and Fitch have withdrawn each of their credit ratings for PG&E Corporation and the Utility as a result of the Chapter 11 Cases. As a result of PG&E Corporation's and the Utility's credit ratings ceasing to be rated at investment grade, the Utility has been required to post additional collateral under its commodity purchase agreements and certain other obligations, and has been exposed to significant constraints on its customary trade credit. In addition, PG&E Corporation and the Utility may be required to post additional collateral in respect of certain other obligations, including workers' compensation and environmental remediation obligations. (See Notes 8 and 11 of the Notes to the Consolidated Financial Statements in Item 1.)

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds.

Financial Resources

Acceleration of Pre-Petition Debt Obligations

The commencement of the Chapter 11 Cases constituted an event of default or termination event with respect to, and caused an automatic and immediate acceleration of, the Accelerated Direct Financial Obligations. Accordingly, as a result of the commencement of the Chapter 11 Cases, the principal amount of the Accelerated Direct Financial Obligations, together with accrued interest thereon, and in case of certain indebtedness, premium, if any, thereon, immediately became due and payable. However, any efforts to enforce such payment obligations are automatically stayed as of the Petition Date, and are subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The material Accelerated Direct Financial Obligations include the Utility's outstanding senior notes, agreements in respect of certain series of pollution control bonds, and PG&E Corporation's term loan facility, as well as short-term borrowings under PG&E Corporation's and the Utility's revolving credit facilities and the Utility's term loan facility disclosed in Note 5 of the Notes to the Condensed Consolidated Financial Statements in Item 1.

DIP Credit Agreement

On February 1, 2019, the Utility borrowed $350 million under the DIP Revolving Facility. On March 29, 2019, the Utility sent a borrowing notice with respect to the full $1.5 billion DIP Initial Term Loan Facility. The DIP Initial Term Loan Facility matures on December 31, 2020 (subject to an extension option described further below) and bears interest at a spread of 225 basis points over LIBOR. On April 3, 2019, the Utility received the proceeds of such borrowing under the DIP Initial Term Loan Facility, net of original issue discount and repayment of the $350 million in outstanding borrowings under the DIP Revolving Facility.

Borrowings under the DIP Facilities are senior secured obligations of the Utility, secured by substantially all of the Utility's assets and entitled to superpriority administrative expense claim status in the Utility's Chapter 11 Case. The Utility's obligations under the DIP Facilities are guaranteed by PG&E Corporation, and such guarantee is a senior secured obligation of PG&E Corporation, secured by substantially all of PG&E Corporation's assets and entitled to superpriority administrative expense claim status in PG&E Corporation's Chapter 11 Case. The DIP Facilities will mature on December 31, 2020, subject to the Utility's option to extend the maturity to December 31, 2021 if certain terms and conditions are satisfied, including the payment of an extension fee. The Utility paid customary fees and expenses in connection with obtaining the DIP Facilities.

As of April 30, 2019, the Utility had outstanding borrowings of $1.5 billion under the DIP Initial Term Loan Facility, no outstanding borrowings under the DIP Delayed Draw Term Loan Facility or the DIP Revolving Facility and $269 in face amount of letters of credit outstanding under the DIP Revolving Facility. As of April 30, 2019, there were undrawn commitments of $500 million and $3.2 billion on the DIP Delayed Draw Term Loan Facility and the DIP Revolving Facility, respectively. Pursuant to the terms of the DIP Credit Agreement, until such time as the DIP Delayed Draw Term Loan Facility has been drawn in full, or the commitments in respect thereof have terminated or expired, further borrowings under the DIP Revolving Facility are not permitted.

CPUC Authorization of DIP Credit Agreement

On January 28, 2019, the CPUC granted the Utility exemptions from the requirement of prior CPUC approval for issuance of debt instruments for the incurrence of the DIP financing. The CPUC also indicated its position that the exemptions do not extend to the transfer of ownership of any Utility asset that is pledged as part of the DIP financing and that in the event of the Utility's default under the DIP financing, the Utility would need to seek the CPUC's approval to execute such a transfer. Further, the CPUC indicated that the Utility's "expenditure of the initial DIP financing funds for any purposes may not be recovered from ratepayers without Commission approval in a future application for rate recovery" and that the Utility "bears the burden of demonstrating the reasonableness of any expenditure."

Equity Financings

There were no issuances under the PG&E Corporation February 2017 equity distribution agreement for the three months ended March 31, 2019.

During the three months ended March 31, 2019, PG&E Corporation issued 8.3 million shares for cash proceeds of $85.2 million under the PG&E Corporation 401(k) plan. The proceeds from these sales were used for general corporate purposes. Beginning January 1, 2019, PG&E Corporation's matching contributions under its 401(k) plan are deposited in cash. Beginning in March 2019, at PG&E Corporation's directive, the 401(k) plan trustee began purchasing new shares in the PCG common stock fund on the open market rather than from PG&E Corporation.

PG&E Corporation does not expect to issue equity for the remaining duration of the Chapter 11 Cases.

Dividends

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility suspended quarterly cash dividends on both PG&E Corporation's and the Utility's common stock, beginning the fourth quarter of 2017, as well as the Utility's preferred stock, beginning the three-month period ending January 31, 2018, due to the uncertainty related to the causes of and potential liabilities associated with the 2018 Camp fire and the 2017 Northern California wildfires. PG&E Corporation does not expect to pay any cash dividends during the Chapter 11 Cases. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1.) Also, on April 3, 2019, the court overseeing the Utility's probation issued an order imposing new conditions of probation, including foregoing issuing "any dividends until [the Utility] is in compliance with all applicable vegetation management requirements" under applicable law and the Utility's wildfire mitigation plan. (See "U.S. District Court Matters and Probation" in Item 1. Legal Proceedings and Item 7. MD&A.)

Utility Cash Flows

The Utility's cash flows were as follows:

	Three Months Ended March 31,	
(in millions)	**2019**	**2018**
Net cash provided by operating activities	$ 2,274	$ 1,516
Net cash used in investing activities	(1,247)	(1,475)
Net cash provided by (used in) financing activities	231	(366)
Net change in cash, cash equivalents and restricted cash	**$ 1,258**	**$ (325)**

Operating Activities

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During the three months ended March 31, 2019, net cash provided by operating activities increased by $758 million compared to the same period in 2018. This increase was due to a reduction in vendor payments as a result of the Chapter 11 Cases, including a reduction in interest paid of $251 million.

The Utility will continue to operate its business as a debtor in possession under the jurisdiction of the Bankruptcy Court and in accordance with applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court. Future cash flow from operating activities will be affected by various ongoing activities, including:

- the timing and amounts of costs, including fines and penalties, that may be incurred in connection with current and future enforcement, litigation, and regulatory matters (see "Enforcement Matters" in Note 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and Part II, Item 1. Legal Proceedings for more information);

- the timing and amount of premium payments related to wildfire insurance (see "Wildfire Insurance" in Note 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1 for more information);

- the Tax Act, which may accelerate the timing of federal tax payments and reduce revenue requirements, resulting in lower operating cash flows depending on the timing of wildfire payments;

- the timing and outcomes of the 2019 GT&S rate case, 2020 GRC, FERC TO18, TO19 and TO20 rate cases, 2018 CEMA filing, 2020 Cost of Capital, NDCTP, and other ratemaking and regulatory proceedings; and

- the timing and amount of substantially increasing costs in connection with the 2019 Wildfire Safety Plan (see "Regulatory Matters" below for more information).

The Utility had material obligations outstanding as of the Petition Date, including claims related to the 2018 Camp fire and 2017 Northern California wildfires. Any efforts to enforce such payment obligations are automatically stayed as of the Petition Date, and are subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. Future cash flows will be materially impacted by the timing and outcome of the Chapter 11 Cases.

Investing Activities

Net cash used in investing activities decreased by $228 million during the three months ended March 31, 2019 as compared to the same period in 2018. The Utility's investing activities primarily consist of the construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

The Utility's capital expenditures were approximately $6.5 billion in 2018. Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately $7.1 billion in capital expenditures in 2019, and $7 billion in 2020.

Financing Activities

Net cash provided by financing activities increased by $597 million during the three months ended March 31, 2019 as compared to the same period in 2018. This increase was primarily due to a long-term debt repayment of $400 million in 2018 with no corresponding activity in 2019. Additionally, the Utility borrowed $350 million in loans under the DIP Revolving Facility and recorded corresponding debt issuance costs of $95 million during the three months ended March 31, 2019, with no corresponding activity in 2018.

Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments.

ENFORCEMENT AND LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Notes 10 and 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, PG&E Corporation and the Utility are involved in other enforcement and litigation matters described in the 2018 Form 10-K and "Part II. Other Information, Item 1. Legal Proceedings."

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. The resolutions of the proceedings described below and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. Discussed below are significant regulatory developments that have occurred since filing the 2018 Form 10-K.

Application for a Waiver of the Capital Structure Condition

The CPUC's capital structure decisions require the Utility to maintain a 52% equity ratio on average over the period that the authorized capital structure is in place, and to file an application for a waiver to the capital structure condition if an adverse financial event reduces its equity ratio by 1% or more. The CPUC's decisions state that the Utility shall not be considered in violation of these conditions during the period the waiver application is pending resolution. Due to the net charges recorded in connection with the 2018 Camp fire and the 2017 Northern California wildfires as of December 31, 2018, the Utility submitted to the CPUC an application for a waiver of the capital structure condition on February 28, 2019. The waiver is subject to CPUC approval. The Utility is unable to predict the timing and outcome of its waiver application.

2020 Cost of Capital Proceeding

On April 22, 2019, the Utility filed an application with the CPUC, requesting that the CPUC authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base beginning on January 1, 2020. In its application, the Utility requested that the CPUC approve the Utility's proposed capital structure (i.e., the relative weightings of common equity, preferred equity, and debt), as well as the proposed return on equity, proposed cost of preferred stock, and proposed cost of debt. The Utility requested a 16% rate of return on equity for 2020, which would result in a $1.2 billion increase in its revenue requirement. The estimated revenue increase is based on the current rate base and does not reflect projected infrastructure investments in 2019 and beyond (see below).

The following table compares the currently authorized capital structure and rates of return which will remain in effect through 2019 with those requested in the Utility's application for 2020:

	2019 Currently Authorized			2020 Requested		
	Cost	Capital Structure	Weighted Cost	Cost	Capital Structure	Weighted Cost
Return on common equity	10.25%	52.00%	5.33%	16.00%	52.00%	8.32%
Preferred stock	5.60%	1.00%	0.06%	5.52%	0.50%	0.03%
Long-term debt	4.89%	47.00%	2.30%	5.16%	47.50%	2.45%
Weighted average cost of capital			7.69%			10.80%

The proposed cost of capital and capital structure will be essential for the Utility to attract new investment capital to upgrade, maintain, and modernize its critical energy infrastructure. The Utility indicated in its application that, over the next four years (2019-2022), the Utility expects to fund up to $28 billion in energy infrastructure investments, including $21 billion in electric and gas safety and reliability and system hardening, $4 billion in new gas pipelines and electric powerlines, $1 billion in power generation, and $2 billion in information technology, equipment and facilities.

The Utility indicated in its application that its requested ROE reflects the wildfire-related challenges that the Utility is facing. The Utility proposed to amend its cost of capital application with an updated cost of capital if the CPUC or the California legislature implemented actions to materially reduce the extent of the wildfire risk-related challenges and structural problems facing customers, the Utility, and its shareholders. The Utility also proposed to file a new cost of capital application with the CPUC on or about the time it emerges from its Chapter 11 proceeding. The Utility requested in its cost of capital application that the annual cost of capital adjustment mechanism be continued, although its normal operation could be superseded by a new cost of capital application. (The annual cost of capital adjustment mechanism is a tool to modify the cost of long-term debt and cost of equity authorized by the CPUC based on changes in interest rates.)

Revenue Requirements

For 2020, the Utility expects that the proposed cost of capital, if adopted, would result in revenue requirement increases of approximately $844 million for electric generation and distribution and $229 million gas distribution operations, assuming 2017 authorized rate base amounts. The revenues for the gas transmission and storage operations would increase by approximately $159 million, assuming 2018 authorized rate base amounts. However, if the CPUC subsequently approves different electric and gas rate base amounts for the Utility in its 2019 GT&S Rate Case and its 2020 GRC, both currently pending before the CPUC, the revenue requirement changes resulting from the Utility's requested 2020 ROE may differ from the amounts reflected in this cost of capital application.

The following table compares the revenue requirement amounts currently authorized in the Utility's 2015 GT&S rate case and the 2017 GRC, with those requested in the Utility's 2020 cost of capital application:

Revenue Requirement (in millions)	**Authorized in 2017 GRC and 2015 GT&S**	**Requested in 2020 Cost of Capital Application**
Electric generation and distribution	$ 6,266	$ 7,110
Gas distribution	1,739	1,968
Gas transmission and storage	$ 1,269	$ 1,428

The Utility is unable to predict the timing and outcome of this proceeding.

As disclosed in "Application for a Waiver of the Capital Structure Condition" above, due to the net charges recorded in connection with the 2018 Camp Fire and the 2017 Northern California wildfires as of December 31, 2018, on February 28, 2019, the Utility submitted to the CPUC an application for a waiver of the capital structure condition. The 2020 cost of capital application does not modify that request.

2017 General Rate Case

On May 11, 2017, the CPUC issued a final decision in the Utility's 2017 GRC, which determined the annual amount of base revenues (or "revenue requirements") that the Utility is authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. The final decision approved, with certain modifications, the settlement agreement that the Utility, PAO, TURN, and 12 other intervening parties jointly submitted to the CPUC on August 3, 2016. Consistent with the amounts proposed in the settlement agreement, the final decision approved a revenue requirement increase of $88 million for 2017, with additional increases of $444 million in 2018 and $361 million in 2019.

On September 24, 2018, the CPUC approved the Utility's advice letter proposal to make a one-time reduction to revenues by approximately $21 million. This advice letter was directed by an ALJ ruling in response to the Utility's $300 million expense reduction announcement in January 2017.

Also, as a result of the Tax Act, on March 30, 2018, the Utility submitted to the CPUC a PFM of the CPUC's final decision in the 2017 GRC. The PFM, if adopted, would reduce revenue requirements by $267 million and $296 million for 2018 and 2019 respectively, and increase rate base by $199 million and $425 million for 2018 and 2019, respectively. The Utility cannot predict the timing and outcome of this PFM.

The Utility provided an update of the cost effectiveness study for the SmartMeter™ Upgrade project to the CPUC on July 10, 2017. On January 31, 2019, the CPUC extended the statutory deadline for the 2017 GRC to August 9, 2019, in order to allow for comments and CPUC action on any PD on the SmartMeter™ upgrade cost effectiveness study. The Utility cannot predict the timing and outcome of any CPUC action in connection with this study and its impact on the 2017 GRC revenue requirement and rate base.

For more information, see the 2018 Form 10-K.

2020 General Rate Case

On December 13, 2018, the Utility filed its 2020 GRC application with the CPUC. In the 2020 GRC, the Utility has requested that the CPUC determine the annual amount of base revenues (or "revenue requirements") that the Utility will be authorized to collect from customers from 2020 through 2022 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. The Utility's request also reflects an updated capital forecast for 2018 and 2019. The 2020 GRC application also includes recorded costs for 2017 and updated forecasts for the proposed mitigations for the period 2018 through 2022 for the Utility's top safety-related risks as presented in the Utility's November 2017 RAMP report.

For 2020, the Utility has requested base revenues of $9.6 billion, an increase of $1.1 billion, or 12.4%, as compared to authorized base revenues for 2019. The requested weighted average rate base for 2020 is approximately $30 billion, which corresponds to an increase of $2.7 billion over the 2019 authorized rate base of $27.3 billion. The Utility also requested that the CPUC establish a ratemaking mechanism that would increase the Utility's authorized revenues in 2021 and 2022 by $454 million and $486 million, respectively. Over the 2020-2022 GRC period, the Utility plans to make average annual capital investments of approximately $4.5 billion in electric distribution, natural gas distribution and electric generation infrastructure, and to improve safety, reliability, and customer service.

Line of Business: (in millions)	**Amounts Requested in the GRC Application**	**Amounts Currently Authorized for 2019 [(1)]**	**Increase (Decrease) to 2019 Authorized Amounts**
Electric distribution	$ 5,113	$ 4,364	$ 749
Gas distribution	2,097	1,963	134
Electric generation	2,366	2,191	175
Total revenue requirements	$ 9,576	$ 8,518	$ 1,058

(1) These amounts include revenues from the Utility's 2017 GRC decision adjusted for attrition year increases, cost of capital, and reductions due to the Tax Act.

Cost Category: (in millions)	**Amounts Requested in the GRC Application**	**Amounts Currently Authorized for 2019 [(1)]**	**Increase (Decrease) to 2019 Authorized Amounts**
Operations and maintenance	$ 2,156	$ 1,946	$ 210
Customer services	319	338	(19)
Administrative and general	1,315	953	361
Less: Revenue credits	(196)	(152)	(44)
Franchise fees, taxes other than income, and other adjustments	236	181	55
Depreciation, return, and income taxes	5,747	5,252	495
Total revenue requirements	**$ 9,576**	**$ 8,518**	**$ 1,058**

(1) These amounts include revenues from the Utility's 2017 GRC decision adjusted for attrition year increases, cost of capital, and reductions due to the Tax Act.
(2) These amounts may appear not to tie due to small rounding differences.

Revenue requirement drivers	Increase to 2019 Authorized Amounts
Community Wildfire Safety Program	6.8%
Liability insurance [(1)]	3.2%
Core gas and electric operations	2.4%
Total proposed revenue requirement increase	12.4%

[(1)] The Utility's GRC forecast indicates that future liability insurance premium costs will be approximately $355 million in 2020

Among other things, the Utility proposed to invest a total of approximately $5 billion (including approximately $3 billion for capital expenditures) between 2018 and 2022 on CWSP measures. Through this program, the Utility proposes to bolster wildfire prevention, risk monitoring, emergency response efforts, and add new and enhanced safety measures, increase vegetation management and harden its electric system to help further reduce wildfire risks.

In addition, the Utility requested authorization to establish several new balancing accounts, including:

- a two-way electric and gas Risk Transfer Balancing Account to record the difference between the amounts adopted for liability insurance premiums and the Utility's actual costs; this two-way account would allow the Utility to pass-through actual insurance costs for up to $2 billion in coverage and return to customers any overcollection if forecast costs exceed actuals costs; and

- a two-way Wildfire Safety Balancing Account to track and record actual incremental expenses and capital revenue requirements associated with the incremental costs of fire risk mitigation work that are not already addressed and recorded in another account; this would include the costs associated with overhead system hardening, enhanced vegetation management, and other incremental costs of wildfire mitigations that are approved by the CPUC in the Utility's annual wildfire mitigation plan. In accordance with SB 901, the Utility submitted its first Wildfire Safety Plan to the CPUC on February 6, 2019.

This GRC proposal did not request funding for potential lawsuits or claims resulting from the 2018 Camp fire and 2017 Northern California wildfires. Also, the Utility is not seeking recovery of compensation of PG&E Corporation's and the Utility's officers. In addition, the Chapter 11 Cases may require a change to the scope of work that the Utility proposes to accomplish in the 2020 GRC period. The Utility also may seek or may be required to update the scope of work for the 2019 Wildfire Safety Plan after such a plan is approved by the CPUC.

In its application, the Utility requests that the CPUC issue a final decision by March 2020 and that the 2020 GRC rates be effective January 1, 2020. On March 8, 2019, the CPUC issued a ruling addressing the schedule and scope of the 2020 GRC. A proposed decision is expected in the first quarter of 2020.

2015 Gas Transmission and Storage Rate Case

In its final decisions in the Utility's 2015 GT&S rate case, the CPUC excluded from rate base $696 million of capital spending in 2011 through 2014. This was the amount recorded in excess of the amount adopted in the 2011 GT&S rate case. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The Utility would be required to take a charge in the future if the CPUC's audit of 2011 through 2014 capital spending resulted in additional permanent disallowance. The audit is still in process. The Utility cannot predict the timing and outcome of the audit.

As a result of the Tax Act, on March 30, 2018, the Utility submitted to the CPUC a PFM of the CPUC's final decision in the 2015 GT&S rate case proposing to reduce revenue requirements by $58 million and increase rate base by $12 million for 2018 (excluding the impacts of an approximately $7 million increase in revenue requirement and a $60 million increase in rate base associated with the Utility's private letter ruling advice letter approved by the CPUC on July 18, 2018). The Utility cannot predict the timing and outcome of this PFM.

For more information, see the 2018 Form 10-K.

2019 Gas Transmission and Storage Rate Case

On November 17, 2017, the Utility filed its 2019 GT&S rate case application with the CPUC for the years 2019 through 2021. The Utility also provided a revenue requirement and rates for 2022, in the event the CPUC adopts an additional year. On October 1, 2018, the Utility entered into a stipulation with PAO that, if approved, would extend the rate case cycle through 2022 as recommended by PAO.

In its application, the Utility requested that the CPUC authorize a 2019 revenue requirement of $1.59 billion to recover anticipated costs of providing natural gas transmission and storage services beginning on January 1, 2019. This corresponds to an increase of $289 million over the Utility’s 2018 authorized revenue requirement of $1.30 billion. The Utility’s request also proposed revenue requirements of $1.73 billion for 2020, $1.91 billion for 2021, and $1.91 billion for 2022 if the CPUC orders a fourth year for the rate case period.

The Utility subsequently revised its forecast revenue requirement as a result of the Tax Act and other forecast updates, including significant reductions in the areas of gas storage facilities and gas system operations programs. The revised revenue requirements are as follows: $1.48 billion for 2019, $1.59 billion for 2020, $1.69 billion for 2021, and $1.68 billion for 2022. The revised 2019 requested revenue requirement corresponds to an increase of $184 million over the Utility’s 2018 authorized revenue requirement.

The requested rate base for 2019 is $4.75 billion, which corresponds to an increase of $1.04 billion over the 2018 adopted rate base of $3.71 billion. The Utility’s request is based on capital expenditure forecasts of $829 million for 2019, $872 million for 2020, and $830 million for 2021 (which exclude common capital allocations). The requested rate base amounts exclude approximately $576 million of capital spending subject to audit by the CPUC related to 2011 through 2014 expenditures in excess of amounts adopted in the 2011 GT&S rate case. The Utility is unable to predict whether the $576 million, or a portion thereof, will ultimately be approved by the CPUC and included in the Utility’s future rate base.

The requested increase in revenue requirement is largely attributable to increased infrastructure investment and costs related to new natural gas storage safety and environmental regulations issued by DOGGR, the Pipeline and Hazardous Materials Safety Administration, and the CPUC.

In response to the Utility’s application, parties proposed various forecast reductions. For example, the PAO recommended a 2019 revenue requirement of $1.35 billion, an increase of $45 million over 2018 adopted amounts. TURN proposed widespread reductions in forecast costs and recommended capital and expense disallowances of more than $500 million.

A second phase of the proceeding addressed the removal of officer compensation costs from the revenue requirement, which is required by SB 901. On March 1, 2019, the Utility, PAO and TURN submitted a joint stipulation to the CPUC proposing to reduce the Utility’s requested 2019 GT&S operating expenses by $1.428 million and capital expenditures by $455,000 for total operating expenses and capital expenditures of $617 million and $829 million, respectively. The Utility is unable to predict the timing and outcome of this proceeding.

For more information, see the 2018 Form 10-K.

Transmission Owner Rate Cases

Transmission Owner Rate Cases for 2015 and 2016 (the "TO16" and "TO17" rate cases, respectively)

On January 8, 2018, the Ninth Circuit Court of Appeals issued an opinion granting an appeal of FERC's decisions in the TO16 and TO17 rate cases that had granted the Utility a 50 basis point ROE incentive adder for its continued participation in the CAISO. Those rate case decisions have been remanded to FERC for further proceedings consistent with the Court of Appeals' opinion. If FERC concludes on remand that the Utility should no longer be authorized to receive the 50 basis point ROE incentive adder, the Utility would incur a refund obligation of $1 million and $8.5 million for TO16 and TO17, respectively. Alternatively, if FERC again concludes that the Utility should receive the 50 basis point ROE incentive adder and provides the additional explanation that the Ninth Circuit found the FERC's prior decisions lacked, then the Utility would not owe any refunds for this issue for TO16 or TO17.

On February 28, 2018, the Utility filed a motion to establish procedures on remand requesting a hearing and additional briefing on the issues identified in the Ninth Circuit Court's opinion. On August 20, 2018, FERC issued an order granting the Utility's motion to allow for additional briefing. The order also consolidated the TO18 rate case with TO16 and TO17 for this issue. The Utility filed briefs on September 19, 2018 and reply briefs on October 10, 2018. The Utility is unable to predict the timing and outcome of FERC's decision.

Transmission Owner Rate Case for 2017 (the "TO18" rate case)

On July 29, 2016, the Utility filed its TO18 rate case at the FERC requesting a 2017 retail electric transmission revenue requirement of $1.72 billion, a $387 million increase over the 2016 revenue requirement of $1.33 billion. The forecasted network transmission rate base for 2017 was $6.7 billion. The Utility is seeking a return on equity of 10.9%, which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO. In the filing, the Utility forecasted that it would make investments of $1.30 billion in 2017 in various capital projects.

On September 30, 2016, the FERC issued an order accepting the Utility's July 2016 filing and set it for hearing, but held the hearing procedures in abeyance for settlement procedures. The order set an effective date for rates of March 1, 2017, and made the rates subject to refund following resolution of the case. On March 17, 2017, the FERC issued an order terminating the settlement procedures due to an impasse in the settlement negotiations reported by the parties. During the hearings held in January 2018, the Utility, intervenors, and the FERC trial staff, addressed questions relating to return on equity, capital structure, depreciation rates, capital additions, rate base, operating and maintenance expense, administrative and general expense, and the allocation of common, general and intangible costs.

Additionally, on March 31, 2017, intervenors in the TO18 rate case filed a complaint at the FERC alleging that the Utility failed to justify its proposed rate increase in the TO18 rate case. On November 16, 2017, the FERC dismissed the complaint. On December 18, 2017, the complainants filed a request for a rehearing of that order, which the FERC denied on May 17, 2018.

On October 1, 2018, the ALJ issued an initial decision in the TO18 rate case proposing a ROE of 9.13% compared to the Utility's request of 10.90%, and an estimated composite depreciation rate of 2.83% compared to the Utility's request of 3.25%. The ALJ also rejected the Utility's method of allocating common plant between CPUC and FERC jurisdiction. In addition, the ALJ proposed to reduce forecasted capital and expense spending to actual costs incurred for the rate case period. Further, the ALJ proposed to remove certain items from the Utility's rate base and revenue requirement. The Utility and intervenors filed initial briefs on October 31, 2018, and reply briefs on November 20, 2018, in response to the ALJ's recommendations. The Utility expects FERC to issue a decision in mid-2019, but expects one or more parties to seek rehearing of that decision and then appeal it to the courts. The Utility is unable to predict the timing of when a final decision will be issued.

Transmission Owner Rate Case for 2018 (the "TO19" rate case)

On July 27, 2017, the Utility filed its TO19 rate case at the FERC requesting a 2018 retail electric transmission revenue requirement of $1.79 billion, a $74 million increase over the proposed 2017 revenue requirement of $1.72 billion. The forecasted network transmission rate base for 2018 is $6.9 billion. The Utility is seeking an ROE of 10.75%, which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO. In the filing, the Utility forecasted capital expenditures of approximately $1.4 billion. On September 28, 2017, the FERC issued an order accepting the Utility's July 2017 filing, subject to hearing and refund, and established March 1, 2018, as the effective date for rate changes. FERC also ordered that the hearings be held in abeyance pending settlement discussion among the parties. On May 14, 2018, the Utility filed a proposal to reflect the impact of the Tax Act on its TO tariff rates effective March 1, 2018, in the resolution of the TO19 rate case. The tax impact reduces the TO19 requested revenue requirement from $1.79 billion to $1.66 billion.

On September 29, 2017, intervenors in the TO19 rate case filed a complaint at the FERC alleging that the Utility failed to justify its proposed rate increase in the TO19 rate case. On October 17, 2017, the Utility requested that the FERC dismiss the complaint. On May 17, 2018, the FERC issued an order setting the complaint for hearing, settlement judge procedures, and consolidation with the TO19 proceeding.

On September 21, 2018, the Utility filed an all-party settlement with FERC in connection with TO19. As part of the settlement, the TO19 revenue requirement will be set at 98.85% of the revenue requirement for TO18 that will be determined in the TO18 final decision. Additionally, if FERC determines that the Utility is not entitled to the 50 basis point incentive adder for the Utility's continued CAISO participation, than the Utility would be obligated to make a refund to customers of approximately $25 million. On December 20, 2018, FERC issued an order approving the all-party settlement.

Transmission Owner Rate Case for 2019 (the "TO20" rate case)

On October 1, 2018, the Utility filed its TO20 rate case at FERC requesting approval of a formula rate for the costs associated with the Utility's electric transmission facilities. On November 30, 2018, the FERC issued an order accepting the Utility's October 2018 filing, subject to hearings and refund, and established May 1, 2019, as the effective date for rate changes. FERC also ordered that the hearings will be held in abeyance pending settlement discussions among the parties. The Utility is unable to predict the timing and outcome of settlement discussions.

The formula rate replaces the "stated rate" methodology that the Utility used in its previous TO rate case filings. The formula rate methodology still includes an authorized revenue requirement and rate base for a given year, but it also provides for an annual update of the following year's revenue requirement and rates in accordance with the terms of the FERC-approved formula. Under the formula rate mechanism, transmission revenues, including Construction Work in Progress, will be updated to the actual cost of service annually. Differences between amounts collected and determined under the formula rate will be either collected from or refunded to customers.

In the filing, the Utility forecasts a 2019 retail electric transmission revenue requirement of $1.96 billion. The proposed amount reflects an approximately 9.5% increase over the as-filed TO19 requested revenue requirement of $1.79 billion (a subsequent reduction to $1.66 billion was identified as a result of the Tax Act). The Utility forecasts that it will make investments of approximately $1.1 billion and $0.7 billion for 2018 and 2019, respectively, for various capital projects to be placed in service before the end of 2019. Including projects to be placed in service beyond 2019, the Utility forecasts total electric transmission capital expenditures of $1.4 billion in 2018 and $1.4 billion in 2019. The Utility's forecasted rate base for 2019 is approximately $8 billion on a weighted average basis, compared to the Utility's forecasted rate base of $6.9 billion in 2018. The Utility has requested that FERC approve a 12.5% return on equity (which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO), an increase from the 10.75% (also inclusive of a 50 basis point CAISO incentive adder) requested in its TO19 rate case. The parties conducted a settlement conference on March 14 - 15, 2019. The next settlement conference is scheduled for June 13 - 14, 2019.

The Utility expects to file an annual update to its TO tariff on or before December 1 of each year beginning in 2019, for rates and charges to become effective January 1 of the following year, consistent with the formula rate.

For more information on the TO rate cases, see the 2018 Form 10-K.

Nuclear Decommissioning Cost Triennial Proceeding

The Utility expects that the decommissioning of Diablo Canyon will take many years after the expiration of its current operating licenses. Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

On December 13, 2018, the Utility submitted its updated decommissioning cost estimate to the CPUC for Diablo Canyon based on a site-specific decommissioning analysis.

On February 14, 2019, the CPUC issued a Scoping Memo authorizing addressing the scope of the NDCTP Proceeding to include reasonableness reviews of the decommissioning cost estimates, ratemaking proposals, proposed milestone framework, plans to address host community needs, and reasonableness of preforming planning activities pre-shutdown including the proposed rate of recovery of these pre-planning activities addressed in Application 18-07-013.

On March 7, 2019, the CPUC amended the scoping memo to combine A.18-07-013, which seeks authorization for the Utility to establish the Diablo Canyon Decommissioning Memorandum Account to track funding for pre-shutdown decommissioning planning activities with the NDCTP A.18-12-008. The CPUC approved the Utility to establish an interim mechanism to track decommissioning planning activity expenses in the Diablo Canyon Decommissioning Memorandum Account. Any Memorandum Account recovery of such expenses is subject to the authorization and approval of the CPUC which will be determined in this year's NDCTP Proceeding.

The Utility seeks to collect $383.7 million and $3.9 million for the funding of Diablo Canyon tax qualified trust and Humboldt Bay tax qualified trust, respectively, commencing January 1, 2020. Additionally, the Utility seeks cost recovery of pre-planning activities commencing January 1, 2020, of $30 million for the 3-year period 2020 to 2022 and a $44 million revenue requirements for the 2-year period 2023 to 2024; by an annual expense only balancing account.

Wildfire Expense Memorandum Account

On June 21, 2018, the CPUC issued a decision granting the Utility's request to establish a WEMA to track specific incremental wildfire liability costs effective as of July 26, 2017. In the WEMA, the Utility can record costs related to wildfires, including: (1) payments to satisfy wildfire claims, including any deductibles, co-insurance and other insurance expense paid by the Utility but excluding costs that have already been forecasted and adopted in the Utility's GRC; (2) outside legal costs incurred in the defense of wildfire claims; (3) insurance premium costs not in rates; and (4) the cost of financing these amounts. Insurance proceeds, as well as any payments received from third parties, or through FERC authorized rates, will be credited to the WEMA as they are received. The WEMA will not include the Utility's costs for fire response and infrastructure costs which are tracked in the CEMA. The decision does not grant the Utility rate recovery of any wildfire-related costs. Any such rate recovery would require CPUC authorization in a separate proceeding. (See Notes 4 and 10 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

As of March 31, 2019, the Condensed Consolidated Financial Statements include long-term regulatory assets of $111 million, consisting of insurance premium costs that are probable of recovery. Should PG&E Corporation and the Utility conclude in future periods that recovery of insurance premiums in excess of amounts included in authorized revenue requirements is no longer probable, PG&E Corporation and the Utility will record a charge in the period such conclusion is reached.

Catastrophic Event Memorandum Account Applications

The CPUC allows utilities to recover the reasonable, incremental costs of responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities through a CEMA. In 2014, the CPUC directed the Utility to perform additional fire prevention and vegetation management work in response to the severe drought in California. The costs associated with this work are tracked in the CEMA. While the Utility believes such costs are recoverable through CEMA, its CEMA applications are subject to CPUC review and approval. For more information see Note 3 of the Notes to the Condensed Consolidated Financial Statements in Item 1.

2016 CEMA Application

In 2016, the Utility submitted a request to the CPUC to authorize recovery under the CEMA tariff for a revenue requirement increase of approximately $146 million for recorded capital and expense costs related to the 2015 drought mitigations and emergency response activities for declared disasters that occurred from December 2012 through March 2016. On January 4, 2018, PAO, TURN, and the Utility filed an all-party motion with the CPUC seeking approval of an all-party settlement agreement. The settlement agreement proposed that the Utility's total CEMA revenue requirement request be reduced by $29 million, from $146 million to $117 million. On June 21, 2018, the CPUC approved the settlement agreement authorizing the Utility to recover $117 million in connection with its 2016 CEMA application.

2018 CEMA Application

On March 30, 2018, the Utility submitted to the CPUC its 2018 CEMA application requesting cost recovery of $183 million in connection with seven catastrophic events that included fire and storm declared emergencies from mid-2016 through early 2017, as well as $405 million related to work performed in 2016 and 2017 to cut back or remove dead or dying trees that were exposed to years of drought conditions and bark beetle infestation. The 2018 CEMA application originally sought cost recovery of $555 million on a forecast basis, subject to true-up if actual costs were greater or less than the forecast, for additional tree mortality and fire risk mitigation work anticipated in 2018 and 2019. On October 12, 2018, the Utility notified the CPUC and other parties that $180 million of the forecasted 2018 and 2019 fire risk mitigation costs would be removed from CEMA and instead pursued in the FHPMA. Upon removal of the $180 million, the Utility's forecast costs for 2018 and 2019 sought in the application would be approximately $375 million. The 2018 CEMA application does not include costs related to the 2015 Butte fire, the 2017 Northern California wildfires, or the 2018 Camp fire.

On November 2, 2018, the assigned ALJ denied the Utility's July 25, 2018 motion requesting interim rate relief for $441 million, which represents 75% of the costs incurred in 2016 and 2017 related to storms, wildfires and tree mortality response work. Subsequently, on December 4, 2018, the Utility filed a renewed motion for interim rate relief, due to worsening financial conditions. The renewed motion for interim relief sought approximately $588 million, which represents 100% of the total costs incurred in 2016 and 2017 for the activities referenced above. The Utility requested that cost recovery occur over a one-year period, with the amounts collected to be subject to refund based on the authorized amount in the proceeding.

On April 25, 2019, the CPUC adopted a decision granting the Utility's request for interim rate relief but allowing for recovery of $373 million of costs (63% of the total costs incurred in 2016 and 2017), and denying cost recovery on a forecast basis. Costs included in the interim rate relief are subject to audit and refund.

PG&E Corporation and the Utility are unable to predict the timing and outcome of the overall proceeding.

Fire Hazard Prevention Memorandum Account

The CPUC allows utilities to track and record costs associated with implementing regulations and requirements adopted to protect the public from potential fire hazards associated with overhead power line facilities and nearby aerial communication facilities that have not been previously authorized in another proceeding. The Utility currently is authorized to track such costs in the FHPMA through the end of 2019. During 2018, the Utility recorded $262 million of costs to the FHPMA, corresponding to vegetation management work performed to comply with CPUC December 2017 fire safety regulations. While the Utility believes such costs are recoverable, rate recovery requires CPUC reasonableness review and authorization in a separate proceeding or through a GRC.

Fire Risk Mitigation Memorandum Account

On March 12, 2019, the CPUC approved the Utility's FRMMA to track costs incurred as of January 1, 2019, for fire risk mitigation activities that are not otherwise covered in revenue requirements. The FRMMA was set forth in SB 901 to capture costs incurred in advance of the CPUC's approval of the Utility's Wildfire Safety Plan. The Utility has proposed that the FRMMA continue after the approval of its 2019 Wildfire Safety Plan to record costs of wildfire mitigation activities identified after such approval. As of March 31, 2019, the Utility incurred $55 million of costs to FRMMA. The Utility will seek recovery of the FRMMA balance in a future application.

Other Regulatory Proceedings

2019 Wildfire Safety Program

On October 25, 2018, the CPUC opened an OIR to implement the provisions of SB 901 related to electric utility wildfire mitigation plans. This OIR provided guidance on the form and content of the initial wildfire mitigation plans, provided a venue for review of the initial plans, and developed and refined the content of and process for review and implementation of wildfire mitigation plans to be filed in future years. In this proceeding the CPUC will consider, among other things, how to interpret and apply SB 901's list of required plan elements, as well as whether additional elements beyond those required in SB 901 should be included in the wildfire mitigation plans. SB 901 also requires, among other things, that such plans include a description of the preventive strategies and programs to be adopted by an electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including the consideration of dynamic climate change risks, plans for vegetation management, and plans for inspections of the electrical corporation's electrical infrastructure. The scope of this proceeding does not include utility recovery of costs related to wildfire mitigation plans, which SB 901 requires to be addressed in separate rate recovery applications.

On February 6, 2019, the Utility filed its wildfire mitigation plan (the "2019 Wildfire Safety Plan") with the CPUC. The 2019 Wildfire Safety Plan also describes forecasted work and investments in 2019 that are designed to help further reduce the potential for wildfire ignitions associated with the Utility's electrical equipment in high fire-threat areas. The 2019 Wildfire Safety Plan specifically addresses wildfire risk factors that occur most frequently and have potential to start or spread a fire. The 2019 Wildfire Safety Plan focuses on the measures of the Utility proposes to take in 2019, but includes longer-term plans, while acknowledging that the Utility may modify these plans based upon new information or conditions as the Utility implements these measures. The new and ongoing safety measures being pursued include:

- Installing nearly 600 new, high-definition cameras, made available to Cal Fire and local fire officials, in high fire-threat areas by 2022, increasing coverage across high fire-threat areas to more than 90%;

- Adding approximately 1,300 additional new weather stations by 2022, at a density of one station roughly every 20 circuit miles in high fire-threat areas;

- Conducting enhanced safety inspections of electric infrastructure in high-fire threat areas, including approximately 735,000 electric towers and poles across approximately 5,700 transmission line miles and 25,200 distribution line miles;

- Further enhancing vegetation management efforts across high and extreme fire-threat areas to address vegetation that poses higher potential for wildfire risk, such as removing or trimming trees from particular "at-risk" tree species that have exhibited a higher pattern of failing;

- Continuing to disable automatic reclosing in high fire-threat areas during wildfire season and periods of high fire-risk and upgrading reclosers and circuit breakers in high fire-threat areas with remote control capabilities;

- Expanding the Public Safety Power Shutoff Program (PSPS) to include all transmission and distribution lines in Tier 2 and Tier 3 High Fire Threat District (HFTD) areas;

- Installing stronger and more resilient poles and covered power lines, including targeted undergrounding, starting in areas with the highest fire risk, ultimately upgrading and strengthening approximately 7,100 miles over the next 10 years; and

- Partnering with additional communities in high fire-threat areas to create new resilience zones that can power central community resources during a Public Safety Power Shutoff.

On February 12, February 14, and April 25, 2019, the Utility filed amendments to the 2019 Wildfire Safety Plan with the CPUC to correct inadvertent errors in the cost table attached to the 2019 Wildfire Safety Plan; refine language in the 2019 Wildfire Safety Plan; and modify certain 2019 Wildfire Safety Plan targets in light of external conditions, enhance other targets based on early learnings, and clarify targets to minimize the potential for misinterpretation, respectively. On April 29, 2019, the ALJs issued two PDs applicable to the Utility: one PD addressing all wildfire mitigation plans filed by California electric utilities and one PD specific to the Utility. These two PDs ordered that, among other things, the Utility submit Advice Letters within 6 and 12 months of the effective date of PD describing concerns with the effectiveness of the Wildfire Safety Plan and submit an Advice Letter on July 30, 2019 proposing "metrics that assess whether the Wildfire Mitigation Plan is having or will have the desired result - a reduction in catastrophic wildfire". The Utility specific PD refused to consider the Utility's proposed April 25 amendments. As a condition of probation, the Utility must fully comply with the specific targets and metrics set forth in the wildfire safety plan ultimately approved by the CPUC. (see "U.S. District Court Matters and Probation" in Part II, Item 1. Legal Proceedings for more information).

The CPUC is expected to issue a decision in the second quarter of 2019. PG&E Corporation and the Utility are unable to predict the timing and outcome of this proceeding. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected if the Utility is unable to timely recover costs in connection with the 2019 Wildfire Safety Plan recorded in a memorandum account, which the Utility expects will be substantial.

OIR to Implement Public Utilities Code Section 451.2 Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901

SB 901, signed into law on September 21, 2018, requires the CPUC to establish a customer harm threshold, directing the CPUC to limit certain disallowances in the aggregate, so that they do not exceed the maximum amount that the Utility can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service (the "Customer Harm Threshold"). SB 901 also authorizes the CPUC to issue a financing order that permits recovery, through the issuance of recovery bonds (also referred to as "securitization"), of wildfire-related costs found to be just and reasonable by the CPUC and, only for the 2017 Northern California wildfires, any amounts in excess of the Customer Harm Threshold. SB 901 does not authorize securitization with respect to possible 2018 Camp fire costs.

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the Customer Harm Threshold in future applications under Section 451.2(a) of the Public Utilities Code. In the OIR, the CPUC stated that "consistent with Section 451.2(a), the determination of what costs and expenses are just and reasonable must be made in the context of an application for the recovery of specific costs related to the 2017 wildfires." Based on the CPUC's interpretation of Section 451.2 as outlined in the OIR, PG&E Corporation and the Utility believe that any securitization of costs relating to the 2017 Northern California wildfires would not occur, if at all, until (a) the Utility has paid claims relating to the 2017 Northern California wildfires, (b) the Utility has filed an application for recovery of such costs, and (c) the CPUC makes a determination that such costs are just and reasonable or in excess of the Customer Harm Threshold. PG&E Corporation and the Utility therefore do not expect the CPUC to permit the Utility to securitize costs relating to the 2017 Northern California wildfires on an expedited or emergency basis. Based on the OIR, as well as prior experience and precedent, and unless the CPUC alters the position expressed in the OIR, PG&E Corporation and the Utility believe it likely would take several years to obtain authorization to securitize any amounts relating to the 2017 Northern California wildfires.

On February 11, 2019, the Utility filed opening comments in response to the OIR in which it argued, among other things, the CPUC should (1) promptly set a Customer Harm Threshold, or at least define the methodology for setting the Customer Harm Threshold with sufficient specificity to enable PG&E Corporation and the Utility and potential investors to anticipate that amount; (2) determine the Customer Harm Threshold based on the capital needed to resolve claims arising from both the 2018 Camp fire and 2017 Northern California wildfires to be provided for in a plan of reorganization; (3) define how the Customer Harm Threshold will be applied to any future wildfires; and (4) establish the Customer Harm Threshold based on the amount of debt the Utility can raise. Based on assumptions set forth in the comments, the Utility indicated that it could borrow up to approximately $3 billion to fund wildfire claims costs as part of a plan of reorganization.

On February 25, 2019, the Utility filed reply comments in response to the OIR and the opening comments of other parties, in which it urged the CPUC to clarify the regulatory construct pertaining to recovery of wildfire costs in order to mitigate the deepening crisis affecting utilities, their customers, their employees, and the State's economy and clean energy goals. The Utility again asked the CPUC to adopt a predictable financial methodology applicable to costs arising from wildfires in 2017, 2018, and future years; and also asked the CPUC to refine prospective cost recovery standards to provide that a utility is deemed prudent if it substantially complies with its wildfire mitigation plan.

On March 29, 2019, the Assigned Commissioner issued a Scoping Memo, which stated that the CPUC in this proceeding will establish a Customer Harm Threshold methodology applicable only to 2017 fires, to be invoked in connection with a future application for cost recovery, and will not determine a specific financial outcome in this proceeding.

On April 5, 2019, the Assigned Commissioner published a Staff Report, describing a proposed stress test to determine the Customer Harm Threshold based on: (1) the maximum additional debt that a utility can take on and maintain a minimum investment-grade credit rating; (2) excess cash available to the utility; and (3) a potential regulatory adjustment upward or downward by a maximum of 20%, to be determined by the CPUC. The Staff Report also proposed two "optional concepts" for ratepayer protection: (1) a de-escalation of the utility's authorized return on equity based on the amount of customer costs in excess of the Customer Harm Threshold, capped at 300 basis points, and (2) equity warrants in favor of customers in the amount of 1% for every $500 million of securitized wildfire liability, capped at 15%. On April 10, 2019, a workshop addressing the Staff Report was held. On April 12, 2019, the Assigned Commissioner extended the time for parties to file comments on the Staff Report, to April 24, 2019 for opening comments and May 1, 2019 for reply comments.

Transportation Electrification

California law SB 350 requires the CPUC, in consultation with the California Air Resources Board and the CEC, to direct electrical corporations to file applications for programs and investments to accelerate widespread TE. In September 2016, the CPUC directed the Utility and the other large IOUs to file TE applications that include both short-term projects (of up to $20 million in total) and two-to-five year programs with a requested revenue requirement determined by the Utility.

On May 31, 2018, the CPUC issued a final decision approving the Utility's two-to-five year program proposals for actual expenditures up to approximately $269 million (including $198 million of capital expenditures), to support utility-owned make-ready infrastructure supporting public fast charging and medium to heavy-duty fleets. In the EV Fleet program, the Utility has a goal of providing make-ready infrastructure at 700 sites supporting 6,500 vehicles, conducting operation and maintenance of installed infrastructure, and educating customers on the benefits of electric vehicles. The final decision gives customers the option of self-funding, installing, owning, and maintaining the make-ready infrastructure installed beyond the customer meter in lieu of utility ownership, after which they would receive a utility rebate for a portion of those costs. The EV Fast Charge program has a goal to install utility-owned make-ready infrastructure at approximately 52 public charging sites amounting to roughly 234 DC fast chargers.

On December 19, 2018, the CPUC initiated a new Rulemaking for vehicle electrification matters (R.18-12-006). This new proceeding will include issues related to utility rate designs supporting transportation electrification and hydrogen fueling stations, a framework for IOUs' transportation electrification investments, and vehicle-grid integration. A pre-hearing conference for this rulemaking was held on March 1, 2019, and a scoping memo will be issued following that conference.

Electric Distribution Resources Plan

As required by California law, on July 1, 2015, the Utility filed its proposed electric DRP for approval by the CPUC. The Utility's DRP identifies its approach for identifying optimal locations on its electric distribution system for deployment of DERs. The Utility's DRP approach is designed to allow distributed energy technologies to be integrated into the larger grid while continuing to provide customers with safe, reliable, and affordable electric service.

As part of the Utility's DRP approach, on June 1, 2018, the Utility filed its first annual distribution grid needs assessment report with the CPUC, and on September 4, 2018, the Utility filed its first distribution deferral opportunity report. The distribution deferral report proposes cost effective electric distribution investments that can be deferred through deployment of dispatchable third-party-owned DERs, or non-wire alternative solutions, to operate during specific grid events. The Utility convened a distribution planning advisory group comprised of CPUC staff, ratepayer and environmental advocates, and DER market participants, to review and provide advisory input to the Utility on its distribution deferral identification process and to identify distribution deferral opportunities. After incorporating the advisory group's input, on November 28, 2018, the Utility filed a proposal with the CPUC for competitively procuring distribution services from third-party owned DERs to defer selected distribution projects. Following the CPUC's approval of the Utility's procurement plan on February 5, 2019, the Utility launched a competitive solicitation and is currently evaluating offers.

On March 26, 2018, the CPUC issued a final decision requiring the Utility to include a grid modernization plan for integrating DERs in the Utility's GRC. The grid modernization plan for DERs must include a narrative 10-year vision for investments needed to support DER growth, while ensuring safety and service reliability. On June 25, 2018, the Utility hosted a public grid modernization workshop for integrating DERs to provide a high-level overview of its vision and 10-year plan and incorporate stakeholder input. On December 13, 2018, the Utility filed its 2020 GRC Application, which includes the Utility's grid modernization vision and plan.

OIR to Consider Strategies and Guidance for Climate Change Adaptation

On April 26, 2018, the CPUC opened an OIR to consider strategies for integrating climate change adaptation matters into relevant CPUC proceedings. Phase one will focus on how to integrate climate change adaptation into the IOUs' existing planning and operations to ensure utility safety and reliability.

The CPUC OIR will consider:

- how to define climate change adaption for the IOUs;
- the climate-driven risks facing the IOUs;

- data, tools, resources, and guidance to instruct utilities on how to incorporate adaption in their existing planning and operational processes; and

- strategies to address climate change in CPUC proceedings, including impacts on disadvantaged communities.

On October 10, 2018, the CPUC issued a scoping memo and established a procedural schedule. A final decision is expected in late 2019.

LEGISLATIVE AND REGULATORY INITIATIVES

Senate Bill 901

SB 901, signed into law on September 21, 2018, requires the CPUC to establish a Customer Harm Threshold (as defined herein), directing the CPUC to limit certain disallowances in the aggregate, so that they do not exceed the Customer Harm Threshold. SB 901 also authorizes the CPUC to issue a financing order that permits recovery, through the issuance of recovery bonds (also referred to as "securitization"), of wildfire-related costs found to be just and reasonable by the CPUC and, only for the 2017 Northern California wildfires, any amounts in excess of the Customer Harm Threshold. SB 901 does not authorize securitization with respect to possible 2018 Camp fire costs.

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the Customer Harm Threshold in future applications under Section 451.2(a) of the Public Utilities Code for cost recovery of 2017 wildfire costs. In the OIR, the CPUC stated that "consistent with Section 451.2(a), the determination of what costs and expenses are just and reasonable must be made in the context of an application for the recovery of specific costs related to the 2017 wildfires." Based on the CPUC's interpretation of Section 451.2 as outlined in the OIR, PG&E Corporation and the Utility believe that any securitization of costs relating to the 2017 Northern California wildfires would not occur, if at all, until (a) the Utility has paid claims relating to the 2017 Northern California wildfires, (b) the Utility has filed application for recovery of such costs, and (c) the CPUC makes a determination that such costs are just and reasonable or in excess of the Customer Harm Threshold. PG&E Corporation and the Utility therefore do not expect the CPUC to permit the Utility to securitize costs relating to the 2017 Northern California wildfires on an expedited or emergency basis. Based on the OIR, as well as prior experience and precedent, and unless the CPUC alters the position expressed in the OIR, PG&E Corporation and the Utility believe it likely would take several years to obtain authorization to securitize any amounts relating to the 2017 Northern California wildfires.

On February 11, 2019, and February 25, 2019, the Utility filed opening and reply comments, respectively, in response to the OIR. On March 29, 2019, the Assigned Commissioner issued a Scoping Memo, which stated that the CPUC in this proceeding will establish a Customer Harm Threshold methodology applicable only to 2017 fires, to be invoked in connection with a future application for cost recovery, and will not determine a specific financial outcome at this time. (See "Regulatory Matters - OIR to Implement Public Utilities Code Section 451.2 Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901" above.)

In addition, SB 901 requires utilities to submit annual wildfire mitigation plans for approval by the CPUC on a schedule to be established by the CPUC. The wildfire mitigation plan must include the components specified in SB 901, such as identification and prioritization of wildfire risks, and drivers for those risks; plans for vegetation management; actions to harden the system, prepare for, and respond to events; and protocols for disabling reclosers and deenergizing the system. The CPUC has three months to approve a utility's plan, with the ability to extend the deadline. The CPUC will conduct an annual compliance review, which will be supported by an independent evaluator's report. The CPUC will complete the compliance review within 18 months. SB 901 establishes factors to be considered by the CPUC when setting penalties for failure to substantially comply with the plan. Costs associated with the wildfire mitigation plan are tracked in a memorandum account, and the costs of implementing the plan will be assessed in each utility's GRC proceeding, or other application proceedings. The Utility is unable to predict the timing or outcome of the CPUC's review of the wildfire mitigation plan, the results of the CPUC compliance review of wildfire mitigation plan implementation, or the timing or extent of cost recovery for wildfire mitigation plan activities.

Finally, SB 901 established a Commission on Catastrophic Wildfire Cost and Recovery to evaluate wildfire reforms, including inverse condemnation reform, a potential state wildfire insurance fund, and other wildfire mitigation measures. The commission, which is composed of five members, is holding multiple meetings throughout the state to accept public and expert testimony and develop recommendations. SB 901 directs the commission, in consultation with the CPUC and California Insurance Commissioner, to prepare a report on or before July 1, 2019, that contains an assessment of issues surrounding catastrophic wildfire costs and damages and makes recommendations for changes to the law. The recommendations of the commission and the response by the Governor and legislature to those recommendations could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Power Charge Indifference Adjustment OIR

On October 11, 2018, the CPUC approved a decision to modify the PCIA methodology, which was developed after the 2001 California energy crisis, which adjusts how customers that leave the Utility's bundled service for CCA or DA service, pay for their share of the costs associated with long-term power purchase commitments made on their behalf. The decision better enables utilities to recover their above market costs from departing customers as compared to the previous methodology, by:

- adopting benchmark values used to set the PCIA rate that more closely resemble actual market prices for resource adequacy and renewable energy credits;
- continuing to allow legacy utility-owned generation costs to be recovered from CCA customers;
- eliminating the 10-year limit on PCIA cost recovery for post-2002 utility owned generation and certain storage costs; and
- adding an annual true-up to the PCIA rate based on market sales.

The Utility anticipates the revised PCIA rate to go into effect as of July 1, 2019.

On December 19, 2018, a prehearing conference was held to initiate phase two of the PCIA proceeding, to further develop proposals for future consideration by the CPUC. On February 1, 2019, the assigned commissioner issued a phase two scoping memo and ruling, which sets forth the category, issues, need for hearing, schedule, and other matters. As indicated in the scoping memo and ruling, phase two of this proceeding will primarily rely upon a working group process to further develop a number of PCIA-related proposals for consideration by the CPUC, which include benchmark true-up for brown power resource adequacy and renewable energy credits, rate design mechanics, portfolio optimization and cost reduction, allocation and auctions, whether the CPUC should consider new or modified shareholder responsibility for future portfolio mismanagement, if any, and CCA and DA prepayment options. The schedule included in the scoping memo and ruling indicates that the CPUC is expected to issue decisions on several topics covered by this OIR starting in late 2019 and extending through 2020.

Strike Force Report

On February 12, 2019, California Governor Gavin Newsom created a "Strike Force" to coordinate the state's efforts relating to the safety, reliability and affordability of energy and directed the Strike Force to develop a roadmap to address the issues of wildfire, climate change and the state's energy sector. On April 12, 2019, the Strike Force publicly issued a report setting out potential steps the state could take to reduce the incidence and severity of wildfires and outlining "actions to hold the state's utilities accountable for their behavior and potential changes to stabilize California's utilities to meet the energy needs of customers and the economy." The Strike Force Report identified three potential concepts for addressing how to allocate the costs resulting from wildfires among stakeholders:

- "A liquidity-only fund that would provide liquidity for utilities to pay wildfire damage claims pending CPUC determination of cost recovery potentially coupled with modification of cost recovery standards.
- "Adopting a fault-based standard that would modify California's strict liability standard to one based on fault to balance the need for public improvements with private harm to individuals.
- "Creation of a catastrophic wildfire fund coupled with a revised cost recovery standard to spread the cost of catastrophic wildfires more broadly among stakeholders."

The Strike Force Report did not include a specific recommendation among the three identified concepts. Later on April 12, 2019, Governor Newsom stated that his goal would be to have legislation passed including at least some of the report's recommendations before the legislative recess on July 12, 2019. The Strike Force Report also included a number of recommendations regarding PG&E Corporation and the Utility, including among others, that their investors should be required to "contribute to any solution adopted by the state to address wildfire liabilities in a way that benefits customers" and that the Utility should be "fully remaking its corporate and safety culture."

Due to uncertainty regarding the specific policy actions that may be taken as a result of the Strike Force Report, including the three concepts outlined above, the impact and timing of the report and any resulting policy actions on PG&E Corporation and the Utility cannot be determined at this time. However, the impact and timing of such actions on PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity, and cash flows could be significant.

ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; the reporting of safety and reliability measures for natural gas storage facilities; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of this Form 10-Q, as well as "Item 1A. Risk Factors" and Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K.)

CONTRACTUAL COMMITMENTS

PG&E Corporation and the Utility enter into contractual commitments in connection with future obligations that relate to purchases of electricity and natural gas for customers, purchases of transportation capacity, purchases of renewable energy, and purchases of fuel and transportation to support the Utility's generation activities. (See "Purchase Commitments" in Note 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1). Contractual commitments that relate to financing arrangements include long-term debt, preferred stock, and certain forms of regulatory financing. For more in-depth discussion about PG&E Corporation's and the Utility's contractual commitments, see "Liquidity and Financial Resources" above and MD&A "Contractual Commitments" in Item 7 of the 2018 Form 10-K.

Off-Balance Sheet Arrangements

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2018 Form 10-K (the Utility's commodity purchase agreements).

RISK MANAGEMENT ACTIVITIES

PG&E Corporation, mainly through its ownership of the Utility, and the Utility are exposed to risks associated with adverse changes in commodity prices, interest rates, and counterparty credit.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for risk mitigation purposes and not for speculative purposes. The Utility's risk management activities include the use of physical and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases. The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. These activities are discussed in detail in the 2018 Form 10-K. There were no significant developments to the Utility's and PG&E Corporation's risk management activities during the three months ended March 31, 2019.

RECENT DEVELOPMENTS

New Chief Executive Officer and Board Members

On April 3, 2019, PG&E Corporation announced the appointment of 10 new directors to the Board of Directors of PG&E Corporation, with seven of the 10 then-incumbent directors stepping down, to be effective later that month. On April 22, 2019, Richard C. Kelly resigned from the Boards of PG&E Corporation and the Utility. Also, PG&E Corporation entered into a Settlement Agreement (the "Settlement Agreement") with Blue Mountain Credit Alternatives Master Fund L.P. (together with its affiliates, "BlueMountain"), who had previously nominated candidates for election to PG&E Corporation's Board of Directors. In connection with the execution and delivery of the Settlement Agreement, among other things, Frederick W. Buckman was appointed to the Boards of Directors of PG&E Corporation and the Utility and BlueMountain withdrew its nominations. The full text of the Settlement Agreement with BlueMountain is attached as an exhibit to PG&E Corporation's Current Report on Form 8-K filed with the SEC on April 23, 2019. As of May 2, 2019, the Boards of Directors of PG&E Corporation and the Utility were each constituted with the following individuals: Richard R. Barrera, Jeffrey L. Bleich, Nora Mead Brownell, Frederick W. Buckman, Cheryl F. Campbell, Fred J. Fowler, William D. Johnson (Utility Board only), Michael J. Leffell, Kenneth Liang, Dominique Mielle, Meridee A. Moore, Eric D. Mullins, Kristine M. Schmidt and Alejandro D. Wolff.

In addition, William D. Johnson has joined PG&E Corporation as its new Chief Executive Officer and President, effective May 2, 2019. In connection with the Settlement Agreement, PG&E Corporation has agreed to engage Christopher A. Hart, a former chairman of the National Transportation Safety Board, to provide consulting services to Mr. Johnson regarding matters of safety.

PG&E Corporation and the Utility expect that these leadership changes will have a significant impact on their operations and financial performance in the future.

Proposed Wildfire Assistance Fund

On May 1, 2019, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court seeking authorization to establish and fund a program (the "Wildfire Assistance Fund") to assist those displaced by the 2018 Camp fire and 2017 Northern California wildfires with the costs of temporary housing and other urgent needs. The Wildfire Assistance Fund is intended to aid certain wildfire claimants who are either uninsured or still in need of assistance for temporary housing expenses or other urgent needs. The Wildfire Assistance Fund would consist of $105 million deposited into a segregated account to be controlled by an independent third-party administrator, who will disburse and administer the funds. The administrator would be responsible for developing the specific eligibility requirements and application procedures for the distribution of the Wildfire Assistance Fund to eligible claimants. Up to $5 million of the Wildfire Assistance Fund could be used to pay administrative expenses. The filing of this motion is not an acknowledgment or admission by PG&E Corporation or the Utility of liability with respect of the 2018 Camp fire and 2017 Northern California wildfires. The motion is scheduled to be heard in the Bankruptcy Court on May 22, 2019.

CRITICAL ACCOUNTING POLICIES

The preparation of the Condensed Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. In addition to those items listed below, PG&E Corporation and the Utility consider their accounting policies for regulatory assets and liabilities, loss contingencies associated with environmental remediation liabilities and legal and regulatory matters, AROs, and pension and other post-retirement benefits plans to be critical accounting policies. These policies are considered critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ materially from these estimates. These accounting policies and their key characteristics are discussed in detail in the 2018 Form 10-K.

Liabilities Subject to Compromise

As a result of the Chapter 11 Cases, the payment of pre-petition indebtedness is subject to compromise or other treatment under a plan of reorganization. The determination of how liabilities will ultimately be settled or treated cannot be made until the Bankruptcy Court confirms a Chapter 11 plan of reorganization and such plan becomes effective. Accordingly, the ultimate amount of such liabilities is not determinable at this time. ASC 852 requires pre-petition liabilities that are subject to compromise to be reported at the amounts expected to be allowed, even if they may be settled for lesser amounts. The amounts

currently classified as liabilities subject to compromise are preliminary and may be subject to future adjustments depending on the Bankruptcy Court actions, further developments with respect to disputed claims, determinations of the secured status of certain claims, the values of any collateral securing such claims, rejection of executory contracts, continued reconciliation or other events.

ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

See the discussion above in Note 3 of the Notes to the Condensed Consolidated Financial Statements in Item 1.

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the risks and uncertainties associated with the Chapter 11 Cases, including, but not limited to, the ability to develop, consummate, and implement a plan of reorganization with respect to PG&E Corporation and the Utility; the ability to develop and obtain applicable Bankruptcy Court, creditor or regulatory approvals; the effect of any alternative proposals, views or objections related to the plan of reorganization; potential complexities that may arise in connection with concurrent proceedings involving the Bankruptcy Court, the U.S. District Court, the CPUC, and the FERC; increased costs related to the Chapter 11 Cases; the ability to obtain sufficient financing sources for ongoing and future operations; disruptions to PG&E Corporation's and the Utility's business and operations and the potential impact on regulatory compliance;

- restrictions on PG&E Corporation's and the Utility's ability to pursue strategic and operational initiatives for the duration of the Chapter 11 Cases;

- increased employee attrition as a result of the filing of the Chapter 11 Cases;

- PG&E Corporation's and the Utility's historical financial information not being indicative of future financial performance as a result of the Chapter 11 Cases;

- the potential delay in emergence from bankruptcy if PG&E Corporation and the Utility are not able to develop and consummate a consensual plan of reorganization and are forced to engage in a contested proceeding;

- the possibility that the DIP Credit Agreement is not sufficient to fund PG&E Corporation's and the Utility's cash requirements through their emergence from bankruptcy;

- the possibility that PG&E Corporation and the Utility may not be able to obtain exit financing on favorable terms or at all;

- the outcome of the U.S. District Court matters and probation;

- the impact of the 2018 Camp fire and the 2017 Northern California wildfires, including whether the Utility will be able to timely recover costs incurred in connection with the wildfires in excess of the Utility's currently authorized revenue requirements; the timing and outcome of the remaining wildfire investigations and the extent to which the Utility will have liability associated with these fires; the timing and amount of insurance recoveries; and potential liabilities in connection with fines or penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency were to bring an enforcement action and determined that the Utility failed to comply with applicable laws and regulations;

- the timing and outcome of claims arising from the 2015 Butte fire, including claims by the OES; the timing and outcome of any proceeding to recover related costs in excess of insurance through rates; and whether any regulatory enforcement proceedings in connection with the 2015 Butte fire will be opened and any additional fines or penalties imposed on the Utility;

- the timing and outcome of issuance of recovery bonds ("securitization") of 2017 Northern California wildfires costs that the CPUC finds just and reasonable;

- the timing and outcome of any policy actions resulting from Governor Newsom's Strike Force Report;

- whether PG&E Corporation and the Utility are able to successfully challenge the application of the doctrine of inverse condemnation to the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire;

- the timing and outcome of future regulatory and legislative developments in connection with SB 901, including the Customer Harm Threshold in connection with the 2017 Northern California wildfires, future wildfire reforms, inverse condemnation reform, a potential state wildfire insurance fund, and other wildfire mitigation measures or other reforms targeted at the Utility;

- the outcome of the Utility's CWSP that the Utility has developed in coordination with first responders, civic and community leaders, and customers, to help reduce wildfire threats and improve safety as a result of climate-driven wildfires and extreme weather, including the Utility's ability to comply with the targets and metrics set forth in the 2019 Wildfire Safety Plan; and the cost of the program, and the timing and outcome of any proceeding to recover such cost through rates;

- whether the Utility will be able to obtain full recovery of its significantly increased insurance premiums, and the timing of any such recovery;

- whether the Utility can obtain wildfire insurance at a reasonable cost in the future, or at all, and whether insurance coverage is adequate for future losses or claims;

- the timing and outcomes of the 2019 GT&S rate case, 2020 GRC, FERC TO18, TO19, and TO20 rate cases, 2018 CEMA, future applications for WEMA, FHPMA and FRMMA, future cost of capital proceeding, and other ratemaking and regulatory proceedings;

- the outcome of the probation and the monitorship imposed by the federal court after the Utility's conviction in the federal criminal trial in 2017, the timing and outcomes of the debarment proceeding, potential reliability penalties or sanctions from the North American Electric Reliability Corporation, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to the Utility's compliance with natural gas- and electric- related laws and regulations, ex parte communications, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

- the effects on PG&E Corporation's and the Utility's reputations caused by the CPUC's investigations of natural gas and electric incidents, the 2018 Camp fire and 2017 Northern California wildfires, locate and mark, improper communications between the CPUC and the Utility, and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

- the implementation of the Safety Culture OII decision approved on November 29, 2018, and the outcome of its phase two proceeding, and future legislative or regulatory actions that may be taken, such as requiring the Utility to separate its electric and natural gas businesses, or restructure into separate entities, or undertake some other corporate restructuring, or implement corporate governance changes;

- whether the Utility can control its costs within the authorized levels of spending, and timely recover its costs through rates; whether the Utility can continue implementing a streamlined organizational structure and achieve project savings, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs; and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

- whether the Utility and its third-party vendors and contractors are able to protect the Utility's operational networks and information technology systems from cyber- and physical attacks, or other internal or external hazards;
- the timing and outcome of the October 1, 2018 request for rehearing of FERC's denial of the complaint filed by the CPUC and certain other parties that the Utility provide an open and transparent planning process for its capital transmission projects that do not go through the CAISO's Transmission Planning Process to allow for greater participation and input from interested parties; and the timing and ultimate outcome of the Ninth Circuit Court of Appeals decision on January 8, 2018, to reverse FERC's decision granting the Utility a 50 basis point ROE incentive adder for continued participation in the CAISO and remanding the case to FERC for further proceedings;
- the outcome of current and future self-reports, investigations, or other enforcement proceedings that could be commenced or notices of violation that could be issued relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion, or replacement of its electric and gas facilities, electric grid reliability, inspection and maintenance practices, customer billing and privacy, physical and cybersecurity, environmental laws and regulations; and the outcome of existing and future SED notices of violations;
- the timing and outcome of any CPUC action in connection with the Utility's SmartMeter™ Upgrade cost-benefit analysis;
- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;
- the impact of SB 100, which was signed into law on September 10, 2018, that increases the percentage from 50% to 60% of California's electricity portfolio that must come from renewables by 2030; and establishes state policy that 100% of all retail electricity sales must come from renewable portfolio standard-eligible or carbon-free resources by 2045;
- how the CPUC and the California Air Resources Board implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, DERs, EVs, and similar matters, including whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether the Utility is able to timely recover its associated investment costs;
- the impact of the California governor's executive order issued on January 26, 2018, to implement a new target of five million zero-emission vehicles on the road in California by 2030;
- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California and the Utility's fossil fuel-fired generation sites;
- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of potential actions, such as legislation, taken by state agencies that may affect the Utility's ability to continue operating Diablo Canyon until its planned retirement;
- the impact of wildfires, droughts, floods, or other weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), downed power lines, and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies, and the reparation and other costs that the Utility may incur in connection with such conditions or events; the impact of the adequacy of the Utility's emergency preparedness; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Utility's insurance coverage is available for these types of claims and sufficient to cover the Utility's liability;
- whether the Utility's climate change adaptation strategies are successful;
- the breakdown or failure of equipment that can cause damages, including fires, and unplanned outages; and whether the Utility will be subject to investigations, penalties, and other costs in connection with such events;

- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;

- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner and on acceptable terms;

- the impact of the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the uncertainty in connection with the 2018 Camp fire and the 2017 Northern California wildfires, the ultimate outcomes of the CPUC's pending investigations, and other enforcement matters will impact the Utility's ability to make distributions to PG&E Corporation;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation;

- changes in the regulatory and economic environment, including potential changes affecting renewable energy sources and associated tax credits, as a result of the current federal administration; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity, and cash flows, see Item 1A. Risk Factors below and a detailed discussion of these matters contained elsewhere in MD&A. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

Additionally, PG&E Corporation and the Utility routinely provide links to the Utility's principal regulatory proceedings before the CPUC and the FERC at http://investor.pgecorp.com, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the "News & Events: Events & Presentations" tab and links to certain documents and information related to the 2018 Camp fire, the 2017 Northern California wildfires, the 2015 Butte fire, and other updates which may be of interest to investors, at http://investor.pgecorp.com, under the "Wildfire Updates" tab, in order to publicly disseminate such information. It is possible that any of these filings or information included therein could be deemed to be material information. The information contained on this website is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC. PG&E Corporation and the Utility are providing the address to this website solely for the information of investors and do not intend the address to be an active link.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and the Utility's primary market risk results from changes in energy commodity prices. PG&E Corporation and the Utility engage in price risk management activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these price risk management activities using forward contracts, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices and interest rates. (See the section above entitled "Risk Management Activities" in MD&A and in Note 8 and Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

ITEM 4. CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of March 31, 2019, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934, as amended, is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms, and (ii) accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended March 31, 2019, that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In addition to the following proceedings, PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's contingencies, see Notes 10 and 11 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and Part I, MD&A: "Enforcement and Litigation Matters."

U.S. District Court Matters and Probation

On August 9, 2016, the jury in the federal criminal trial against the Utility in the United States District Court for the Northern District of California, in San Francisco, found the Utility guilty on one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act. On January 26, 2017, the court issued a judgment of conviction against the Utility. The court sentenced the Utility to a five-year corporate probation period, oversight by the Monitor for a period of five years, with the ability to apply for early termination after three years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service.

The probation includes a requirement that the Utility not commit any local, state, or federal crimes during the probation period. As part of the probation, the Utility has retained the Monitor at the Utility's expense. The goal of the Monitor is to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of its gas and electric operations, and to maintain effective ethics, compliance and safety related incentive programs on a Utility-wide basis.

On November 27, 2018, the court overseeing the Utility's probation issued an order requiring that the Utility, the United States Attorney's Office for the Northern District of California (the "USAO") and the Monitor provide written answers to a series of questions regarding the Utility's compliance with the terms of its probation, including what requirements of the Utility's probation "might be implicated were any wildfire started by reckless operation or maintenance of PG&E power lines" or "might be implicated by any inaccurate, slow, or failed reporting of information about any wildfire by PG&E." The court also ordered the Utility to provide "an accurate and complete statement of the role, if any, of PG&E in causing and reporting the recent 2018 Camp fire in Butte County and all other wildfires in California" since January 2017 ("Question 4 of the November 27 Order"). On December 5, 2018, the court issued an order requesting that the Office of the California Attorney General advise the court of its view on "the extent to which, if at all, the reckless operation or maintenance of PG&E power lines would constitute a crime under California law." The responses of the Attorney General were submitted on December 28, 2018, and the responses of the Utility, the USAO and the Monitor were submitted on December 31, 2018.

On January 3, 2019, the court issued a new order requiring that the Utility provide further information regarding the Atlas fire. The court noted that "[t]his order postpones the question of the adequacy of PG&E's response" to Question 4 of the November 27 Order. On January 4, 2019, the court issued another order requiring that the Utility provide "with respect to each of the eighteen October 2017 Northern California wildfires that [Cal Fire] has attributed to [the Utility's] facilities," information regarding the wind conditions in the vicinity of each fire's origin and information about the equipment allegedly involved in each fire's ignition. The responses of the Utility were submitted on January 10, 2019.

On January 9, 2019, the court ordered the Utility to appear in court on January 30, 2019, as a result of the court's finding that "there is probable cause to believe there has been a violation of the conditions of supervision" with respect to reporting requirements related to the 2017 Honey fire. In addition, on January 9, 2019, the court issued an order (the "January 9 Order") proposing to add new conditions of probation that would require the Utility, among other things, to:

- prior to June 21, 2019, "re-inspect all of its electrical grid and remove or trim all trees that could fall onto its power lines, poles or equipment in high-wind conditions, . . . identify and fix all conductors that might swing together and arc due to slack and/or other circumstances under high-wind conditions[,] identify and fix damaged or weakened poles, transformers, fuses and other connectors [and] identify and fix any other condition anywhere in its grid similar to any condition that contributed to any previous wildfires;"

- "document the foregoing inspections and the work done and . . . rate each segment's safety under various wind conditions;" and

- at all times from and after June 21, 2019, "supply electricity only through those parts of its electrical grid it has determined to be safe under the wind conditions then prevailing."

The Utility was ordered to show cause by January 23, 2019 as to why the Utility's conditions of probation should not be modified as proposed. The Utility's response was submitted on January 23, 2019. The court requested that Cal Fire file a public statement, and invited the CPUC to comment, by January 25, 2019. On January 30, 2019, the court found that the Utility had violated a condition of its probation with respect to reporting requirements related to the 2017 Honey fire. The court issued an order stating that a sentencing hearing on the probation violation will be set at a later date. Also, on January 30, 2019, the court ordered the Utility to submit to the court on February 6, 2019 the 2019 Wildfire Safety Plan that the Utility was required to submit to the CPUC by February 6, 2019 in accordance with SB 901, and invited interested parties to comment on such plan by February 20, 2019. In addition, on February 14, 2019, the court ordered the Utility to provide additional information, including on its vegetation clearance requirements. The Utility submitted its response to the court on February 22, 2019. As of April 30, 2019, to the Utility's knowledge, no parties have submitted comments to the court on the 2019 Wildfire Safety Plan.

On March 5, 2019, the court issued an order proposing to add new conditions of probation that would require the Utility, among other things, to:

- "fully comply with all applicable laws concerning vegetation management and clearance requirements;"

- "fully comply with the specific targets and metrics set forth in its wildfire mitigation plan, including with respect to enhanced vegetation management;"

- submit to "regular, unannounced inspections" by the Monitor "of PG&E's vegetation management efforts and equipment inspection, enhancement, and repair efforts" in connection with a requirement that the Monitor "assess PG&E's wildfire mitigation and wildfire safety work;"

- "maintain traceable, verifiable, accurate, and complete records of its vegetation management efforts" and report to the Monitor monthly on its vegetation management status and progress; and

- "ensure that sufficient resources, financial and personnel, including contractors and employees, are allocated to achieve the foregoing" and to forego issuing "any dividends until [the Utility] is in compliance with all applicable vegetation management requirements as set forth above."

The court ordered all parties to show cause by March 22, 2019, as to why the Utility's conditions of probation should not be modified as proposed. The responses of the Utility, the USAO, Cal Fire, the CPUC, and non-party victims were filed on March 22, 2019. At a hearing on April 2, 2019, the court indicated it would impose the new conditions of probation proposed on March 5, 2019, on the Utility, and on April 3, 2019, the Court issued an order imposing the new terms though amended the second condition to clarify that "[f]or purposes of this condition, the operative wildfire mitigation plan will be the plan ultimately approved by the CPUC." Also, on April 2, 2019, the court directed the parties to submit briefing by April 16, 2019, regarding whether the court can extend the term of probation beyond 5 years in light of the violation that has been adjudicated and whether the third-party Monitor reports should be made public. The responses of the Utility, the USAO, and the Monitor were filed on April 16, 2019. The Utility's response contended that the term of probation may not be extended beyond five years and the USAO's response contended that whether the term of probation could be extended beyond five years was an open legal issue.

Order Instituting an Investigation into PG&E Corporation's and the Utility's Safety Culture

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents. The SED engaged a consultant to assist in the SED's investigation and the preparation of a report containing the SED's assessment, and subsequently, to report on the implementation by the Utility of the consultant's recommendations.

On May 8, 2017, the CPUC released the consultant's report, accompanied by a scoping memo and ruling. The scoping memo established a second phase in the OII in which the CPUC evaluated the safety recommendations of the consultant. Phase two of the proceeding also considered all necessary measures, including, but not limited to, a potential reduction of the Utility's return on equity. On November 17, 2017, the CPUC issued a phase two scoping memo and procedural schedule. The scoping memo directed the Utility to file testimony addressing a number of issues including: adoption of the safety recommendations from the consultant, the Utility's implementation process for the safety recommendations of the consultant, the Utility's Board of Director's actions and initiatives related to safety culture and the consultant's recommendations, the Utility's corrective action program, and the Utility's response to certain specified safety incidents that occurred in 2013 through 2015.

The Utility's testimony was submitted to the CPUC on January 8, 2018 and stated that the Utility agrees with all the recommendations of the consultant and supports their adoption by the CPUC. Other parties' responsive testimony was submitted on February 16, 2018, followed by the Utility's rebuttal testimony on February 23, 2018.

On November 29, 2018, the CPUC approved the PD in connection with this proceeding. The decision directed the Utility to implement the recommendations set forth in the May 2017 consultant report no later than July 1, 2019, and to submit quarterly reports on the Utility's implementation status beginning in the fourth quarter of 2018.

On December 21, 2018, the CPUC issued a Scoping Memo and Ruling (the "Scoping Memo") setting forth the scope to be addressed in the next phase of its ongoing investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards (the "Safety Culture OII"). The Scoping Memo provides that the CPUC "will examine [PG&E's] current corporate governance, structure, and operations to determine if the utility is positioned to provide safe electrical and gas service, and will review alternatives to the current management and operational structures of providing electric and gas service in Northern California."

In the Scoping Memo, the CPUC alleges that the Utility has had "serious safety problems with both its gas and electric operations for many years" and that despite penalties and other remedial measures in connection with these problems, PG&E Corporation and the Utility have failed to develop "a comprehensive enterprise-wide approach to addressing safety." The Scoping Memo outlines a number of proposals to address the CPUC's concerns regarding PG&E Corporation's and the Utility's safety culture, including, but not limited to, (i) replacement of all or part of PG&E Corporation's and the Utility's existing boards of directors and corporate management, (ii) separating the Utility's gas and electric distribution and transmission businesses into separate companies, (iii) reorganizing the Utility into regional subsidiaries based on regional distinctions, (iv) reconstituting the Utility as a publicly owned utility or utilities, (v) providing for entities other than the Utility to provide generation services, and (vi) conditioning the Utility's return on equity on safety performance. The Scoping Memo does not propose penalties and states that this phase "is not a punitive phase." The Utility submitted its background filing to the CPUC on January 16, 2019 and opening comments were filed on February 13, 2019. The Utility and other parties filed reply comments on February 28, 2019. Subsequently, the CPUC held workshops on some of the topics raised in the Scoping Memo on April 15, 2019 and April 26, 2019.

The Utility is unable to predict the timing and outcome of this proceeding.

Diablo Canyon Power Plant

For more information regarding the status of the 2003 settlement agreement between the Central Coast Regional Water Quality Control Board, the Utility, and the California Attorney General's Office, see Part I, Item 3. "Legal Proceedings" in the 2018 Form 10-K.

ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, see the section of the 2018 Form 10-K entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Forward-Looking Statements."

PG&E Corporation's and the Utility's financial results could be materially affected as a result of legislative and regulatory developments.

The Utility's financial results could be materially affected as a result of SB 901 adopted in 2018 by the California legislature. In December 2018, the CPUC opened an OIR in connection with SB 901 that will adopt criteria and a methodology for use by the CPUC in future applications for cost recovery of wildfire costs. Following SB 901, in applications for cost recovery in connection with the 2017 Northern California wildfires, the CPUC is expected to consider the Utility's financial status and determine the maximum amount the Utility can pay without harming customers or materially impacting its ability to provide adequate and safe service, and ensure that the costs or expenses that are disallowed for recovery in rates assessed for the wildfires, in the aggregate, do not exceed that amount. The Utility is unable to predict the timing or outcome of such future determination by the CPUC and its impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

In addition, SB 901 requires utilities to submit annual wildfire mitigation plans for approval by the CPUC on a schedule to be established by the CPUC. SB 901 establishes factors to be considered by the CPUC when setting penalties for failure to substantially comply with the plan. The Utility is unable to predict the timing or outcome of the CPUC's review of the wildfire mitigation plan, the results of the CPUC compliance review of wildfire mitigation plan implementation, or the timing or extent of cost recovery for wildfire mitigation plan activities. (See "Regulatory Matters - Other Regulatory Proceedings" in Item 2. MD&A.)

Finally, SB 901 established a Commission on Catastrophic Wildfire Cost and Recovery to evaluate wildfire reforms, including inverse condemnation reform, a potential state wildfire insurance fund, and other wildfire mitigation measures. The recommendations of the CPUC and the response by the Governor and legislature to those recommendations could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. (See "Regulatory Matters - Legislative and Regulatory Initiatives" in Item 2. MD&A.)

On April 12, 2019, California Governor Gavin Newsom's "Strike Force" issued a report setting out potential steps the state could take to reduce the incidence and severity of wildfires and outlining "actions to hold the state's utilities accountable for their behavior and potential changes to stabilize California's utilities to meet the energy needs of customers and the economy." Due to uncertainty regarding the specific policy actions that may be taken as a result of the Strike Force Report, the impact and timing of the report and any resulting policy actions on PG&E Corporation and the Utility cannot be determined at this time. However, the impact and timing of such actions on PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity, and cash flows could be significant. (See "Regulatory Matters - Strike Force Report" in Item 2. MD&A.)

In June 2018, the State of California enacted the California Consumer Privacy Act of 2018 (the "CCPA"), which will come into effect on January 1, 2020, with a 12-month look-back period requiring compliance by January 1, 2019. The CCPA requires companies that process information on California residents to make new disclosures to consumers about their data collection, use and sharing practices, allows consumers to opt out of certain data sharing with third parties and provides a new cause of action for data breaches. The CCPA provides for financial penalties in the event of non-compliance and statutory damages in the event of a data security breach. However, California legislators have stated that they intend to propose amendments to the CCPA, and it remains unclear what, if any, modifications will be made to the CCPA or how it will be interpreted.

The Utility's insurance coverage may not be sufficient to cover losses caused by an operating failure or catastrophic events, including severe weather events, or may not be available at a reasonable cost, or available at all.

The Utility has experienced increased costs and difficulties in obtaining insurance coverage for wildfires and other risks that could arise from the Utility's ordinary operations. PG&E Corporation, the Utility or its contractors and customers could continue to experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of the Utility's insurance coverage. Uninsured losses and increases in the cost of insurance may not be recoverable in customer rates. A loss that is not fully insured or cannot be recovered in customer rates could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

As a result of the potential application to investor-owned utilities of a strict liability standard under the doctrine of inverse condemnation, recent losses recorded by insurance companies, the risk of increased wildfires including as a result of the drought, the 2018 Camp fire, the 2017 Northern California wildfires, and the 2015 Butte fire, the Utility may not be able to obtain sufficient insurance coverage in the future at a reasonable cost, or at all. In addition, the Utility is unable to predict whether it would be allowed to recover in rates the increased costs of insurance or the costs of any uninsured losses.

If the amount of insurance is insufficient or otherwise unavailable, or if the Utility is unable to obtain insurance at a reasonable cost or recover in rates the costs of any uninsured losses, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the quarter ended March 31, 2019, PG&E Corporation did not make any equity contributions to the Utility. Also during the quarter ended March 31, 2019, PG&E Corporation did not make any sales of unregistered equity securities in reliance on an exemption from registration under the Securities Act of 1933, as amended.

Issuer Purchases of Equity Securities

During the quarter ended March 31, 2019, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. PG&E Corporation does not have any preferred stock outstanding. During the quarter ended March 31, 2019, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 6. EXHIBITS

EXHIBIT INDEX

3.1	Bylaws of PG&E Corporation amended as of April 10, 2019
3.2	Bylaws of Pacific Gas and Electric Company amended as of April 5, 2019
10.1	Settlement Agreement, dated April 22, 2019, by and between PG&E Corporation and BlueMountain Capital Management, LLC (incorporated by reference to PG&E Corporation's Form 8-K dated April 22, 2019 (File No. 1-12609), Exhibit 10.1)
10.2	Senior Secured Superpriority Debtor-in-Possession Credit, Guaranty and Security Agreement, dated February 1, 2019, among Pacific Gas and Electric Company, PG&E Corporation, the financial institutions from time to time party thereto, as lenders and issuing lenders, JPMorgan Chase Bank, N.A., as administrative agent, and Citibank, N.A., as collateral agent (incorporated by reference to PG&E Corporation's Form 8-K dated February 1, 2019 (File No. 1-12609), Exhibit 10.1)
*10.3	Separation Agreement between PG&E Corporation and Geisha J. Williams dated January 12, 2019 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2018 (File No. 1-12609), Exhibit 10.21)
*10.4	Separation Agreement between Pacific Gas and Electric Company and Pat Hogan dated January 7, 2019 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2018 (File No. 1-2348), Exhibit 10.22)
31.1	Certifications of Principal Executive Officer and Principal Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of Principal Executive Officers and Principal Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certifications of Principal Executive Officer and Principal Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certifications of Principal Executive Officers and Principal Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

*Management contract or compensatory agreement.
**Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this Quarterly Report on Form 10-Q to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

/s/ JASON P. WELLS

Jason P. Wells
Senior Vice President and Chief Financial Officer
(duly authorized officer and principal financial officer)

PACIFIC GAS AND ELECTRIC COMPANY

/s/ DAVID S. THOMASON

David S. Thomason
Vice President, Chief Financial Officer and Controller
(duly authorized officer and principal financial officer)

Dated: May 2, 2019